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Volume 3 of 3 Volumes

ORIGINAL

Assessment of Methane-Related Fuels for Automotive Fleet Vehicles

Appendices

February 1982

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Prepared for:
U.S. Department of Energy
Assistant Secretary for Conservation and Renewable Energy
Office of Vehicle and Engine R & D
Under Contract No. DE-AC01-80CS50179

Alternative Fuels Utilization Program

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Prepared by:
Energy Conservation Directorate
The Aerospace Corporation
El Segundo, California 90245
Under Contract No. DE-AC01-80CS50179

Prepared for:
U.S. Department of Energy
Assistant Secretary for Conservation and Renewable Energy
Office of Vehicle and Engine R & D
Washington, DC 20585

Alternative Fuels Utilization Program

II

FOREWORD

This report, prepared by The Aerospace Corporation for the Office of Vehicle and Engine R&D of the Department of Energy, provides an assessment of issues related to the supply and use of methane-related fuels in automotive spark-ignition and diesel engines. The term methane, as used in this report, includes and is interchangeable with natural gas as well as synthetic (or substitute) natural gas derived from coal, biomass, waste products or other renewable resources, provided methane is the predominant constituent. Methanol was included in this study because it is a liquid fuel producible from either natural gas or the same resources as synthetic natural gas. The assessment is based primarily on a comprehensive review of the open literature, supplemented by discussions with manufacturers and users of automotive natural gas systems and related equipment.

The report is divided into three volumes. This volume, Volume III, Appendices, provides data and evaluations in several technical areas which supplement Volume II assessments. Also included are the comments submitted by two organizations after their review of the draft report.

Volume I, Executive Summary, provides summaries of results for all technical, supply, and economic assessments, and identifies research needed for the expanded use of natural gas in the automotive sector.

Volume II, Technical, Supply, and Economic Assessments, provides documentation of all study efforts and results. The areas addressed include vehicle fuel system and fueling station technology; vehicle performance, fuel economy, and emissions; resource energy utilization efficiency; potential petroleum displacement by alternative-fueled fleets; fuel supply; vehicle safety; user economics; and research needs.

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ABSTRACT

This report assesses the use of methane-related fuels, derived from a variety of sources, in highway vehicles. The term methane, as used in this report, includes and is interchangeable with natural gas (NG) as well as synthetic (or substitute) natural gas (SNG), provided methane is the predominant constituent. Methanol is included in this study because it can be produced from NG or the same resources as SNG, and because it is a liquid fuel at normal ambient conditions. Technological, operational, efficiency, petroleum displacement, supply, safety, and economic issues are analyzed. The assessment is intended to satisfy Section 7(a) of the Methane Transportation Research, Development, and Demonstration Act of 1980 (PL 96-512), which focuses on expanded methane use in automotive fleet vehicles and farm equipment. Evaluations of institutional barriers and other alternative fuels were not included in this contract.

About 275,000 Italian and 20,000 domestic vehicles presently use NG. Conversion kits are commercially available for spark-ignition engines, but not for diesel vehicles. A typical dual-fuel (NG or gasoline) light-duty vehicle conversion costs $1250 to $2050, adds 175 to 300 pounds to vehicle weight, and adds to the gasoline driving range a range of 60 to 120 miles on compressed natural gas (CNG), or 200 to 400 miles on cryogenic liquefied natural gas (LNG). Both CNG and LNG require special fueling facilities and vehicle tanks. Methanol conversions are commercially available for $1500 to $2200. They do not significantly affect vehicle weight, but diminish driving range by 35 to 50 percent unless tank size is increased. For the most part, methanol fueling facilities and fuel systems are similar to those for gasoline, except for the use of different materials.

In principle, both NG and methanol allow more efficient engine operation than gasoline. In practice, engines are at present rarely optimized for NG and methanol. On the basis of energy expended from resource extraction to end use, only optimized LNG vehicles are more

efficient than their gasoline counterparts. By 1985, up to 16 percent of the total United States petroleum-based highway vehicle fuel could be displaced by large fleets with central NG fueling depots. Excluding diesel vehicles, which need technology advances to use NG, savings of 8 percent are projected. Methanol use by large fleets could displace up to 8 percent of petroleum-based highway vehicle fuel from spark-ignition vehicles and another 9 percent from diesel vehicles with technology advances.

United States NG supply appears adequate to accommodate fleet use. Supply projections, future price differential versus gasoline, and user economics are uncertain. In many cases, attractive paybacks can occur. CNG now costs on average about $0.65 less than gasoline, per energy-equivalent gallon. Methanol supply projections, future prices, and user economics are even more uncertain. Current and projected near-term methanol supplies are far from adequate to support fleet use. Methanol presently costs more than gasoline on an equal-energy basis, but is projected to cost less if produced from coal instead of NG or petroleum.

ACKNOWLEDGMENTS

Appreciation is acknowledged for the guidance and assistance provided by Dr. Ralph D. Fleming of the Department of Energy, Office of Vehicle and Engine R&D, who served as Project Manager for this study. Appreciation is also extended to many individuals and organizations who provided reference material and reviewed the draft of the report. In particular, the cooperation of Dual Fuel Systems, Inc., the Gas Service Energy Corporation, and the Environmental Protection Agency, who participated in the vehicle test program, is gratefully acknowledged.

During the course of this effort, industry involvement was solicited at all stages, from the study definition workshop in August 1980, through three bimonthly review meetings, and in two successive reviews of draft material. The cooperation of the following organizations in that process is gratefully acknowledged: American Gas Association; Argonne National Laboratory; Beech Aircraft Corporation; CNG Services, Inc.; Dual Fuel Systems, Inc.; Escher:Foster Technology Associates, Inc.; Ford Motor Company; Gas Service Energy Corporation; General Motors Corporation; Institute of Gas Technology; LNG Services, Inc.; Mueller Associates, Inc.; NCF Industries; New York State Energy Office; United States Environmental Protection Agency; and United States General Services Administration. Many constructive comments and suggestions were received from the reviewers, and these are incorporated in this report. In addition, appreciation is extended to the current users and developers of natural gas and methanol equipment who cooperated in providing data for this study.

The report is based on work performed by J. E. Clark, R. R. Covey, J. J. Donnelly, Jr., A. S. Levine, D. L. Levine, M. K. Martin, W. U. Roessler, and H. M. White.

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APPENDIX A

FUEL COMPOSITION AND PROPERTIES

APPENDIX A
FUEL COMPOSITION AND PROPERTIES

Physical and thermochemical properties of conventional and alternative fuels of interest in this study are briefly reviewed in Volume II. This appendix provides an expanded discussion of fuel properties affecting vehicle operation and fueling. The first subject addressed is the variable composition of both pipeline natural gas (NG) and liquefied natural gas (LNG), and its effect on other important fuel properties. Another interesting, but potentially troublesome, characteristic of moist NG is its tendency to form solid hydrates that can plug piping and valves, and this is the second topic covered. Finally, the significance of the autoignition temperature as reported in the literature is discussed in an attempt to clarify the limitations of this fuel ignitability parameter.

A.1 NATURAL GAS COMPOSITION

The composition of NG distributed to consumers in the United States varies considerably, as can be seen in Table A-1. Although these data are primarily from a survey of two decades ago, there is apparently still much variability, as reflected in the range of heating values shown in Table A-2. A part of these differences is due to basic in-ground variations in gas composition. The rest arises from the degree of gas processing used, e.g., the amount of non-methane hydrocarbons removed. Because of their value as petrochemical feedstocks or liquefied petroleum gas (LPG), there has been a tendency in recent years to remove increasing percentages of ethane, propane, and butane, with an accompanying reduction in volumetric heating value of the NG. Thus, the gas in Table A-1 averages near 1050 Btu per standard cubic foot (scf), whereas a more typical current value is 1025 Btu/scf.

For use in this study, a "typical" NG composition was formulated with this average heating value, as shown in Table A-3. In Table A-4, this NG is compared to pure methane in terms of density, heating value, and compressibility factor. NG heating values are about 12 Btu/scf, or 1.2 percent, higher and the density is 5.0 percent higher than methane.

Table A-1. Natural Gas Composition in Various Cities in the United States, Based on 1962 Survey by AGA (Ref. A-2)

		GAS COMPONENTS [1] VOLUME PERCENT									HEATING VALUE,[2]	SPECIFIC
NO.	CITY	METHANE	ETHANE	PROPANE	BUTANES	PENTANES	HEXANES PLUS	CO_2	N_2	MISC.	BTU/CU FT	GRAVITY
1	ABILENE, TEX.	73.52	13.23	4.35	0.56	0.06	0.11	0.16	..01		1121	0.710
2	AKRON, OHIO	93.30	3.49	0.69	.18	.04	.00	0.50	1.80		1037	.600
3	ALBUQUERQUE, N.M.	86.10	9.49	2.34	.44	.08	.03	1.02	0.50		1120	.645
4	ATLANTA, GA	93.42	2.80	0.65	.33	.12	.10	1.38	1.20		1031	.604
5	BALTIMORE, MD.	94.40	3.40	0.60	.50	.00	.00	0.60	0.50		1051	.590
6	BIRMINGHAM, ALA	93.14	2.50	0.67	.32	.12	.05	1.06	2.14		1024	.599
7	BOSTON, MASS	93.51	3.82	0.93	.28	.07	.06	0.94	0.39		1057	.604
8	BROOKLYN, NY.	94.52	3.29	0.73	.26	.10	.09	0.70	0.31		1049	.595
9	BUTTE, MONT.	87.38	3.02	1.09	.11	.06	.00	1.98	6.36		1000	.610
10	CANTON, OHIO	93.30	3.49	0.69	.18	.04	.00	0.50	1.80		1037	.600
11	CHEYENNE, WYO.	91.00	4.73	1.20	.30	.06	.04	1.86	0.81		1060	.610
12	CINCINNATI, OHIO	94.25	3.98	0.57	.16	.03	.03	0.68	0.30		1031	.591
13	CLEVELAND, OHIO	93.30	3.49	0.69	.18	.04	.00	.50	1.80		1037	.600
14	COLUMBUS, OHIO	93.54	3.58	0.66	.22	.06	.03	.85	1.11		1028	.597
15	DALLAS, TEX.	86.30	7.25	2.78	.48	.07	.02	.63	2.47		1093	.641
16	DENVER, COLO.	81.11	6.01	2.10	.57	.17	.03	.42	9.19		1[illegible]1	.659
17	DES MOINES, IOWA	80.38	6.39	2.46	.61	.08	.03	.20	9.53	0.32 He	1012	.669
18	DETROIT, MICH.	89.92	4.21	1.34	.34	.09	.01	.59	3.30	.20 He	1016	.616
19	EL PASO, TEX.	86.92	7.95	2.16	.16	.00	.00	.04	2.72	.05 He	1082	.630
20	FT. WORTH, TEX.	85.27	8.43	2.98	.62	.09	.04	.27	2.30		1115	.649
21	HOUSTON, TEX.[3]	92.50	4.80	2.00	.30	-	-	.27	0.13		1031	.623
22	KANSAS CITY, MO.[4]	87.36	6.66	1.48	.22	.03	TRACE	0.60	3.46	.12 He	1050	.621
23	LITTLE ROCK, ARK.	94.00	3.00	0.50	.20	.20	-	1.00	1.10		1035	.590
24	LOS ANGELES, CALIF.	86.50	8.00	1.90	.30	.10	.10	0.50	2.60		1084	.638
25	LOUISVILLE, KY.	94.05	3.41	0.40	.13	.05	.09	1.20	0.67		1034	.596
26	MEMPHIS, TENN.	92.50	4.37	0.62	.18	.07	.10	1.60	0.56		1044	.608
27	MILWAUKEE, WIS.	89.01	5.19	1.89	.66	.44	.02	0.00	2.73	.06 He	1051	.627
28	NEW ORLEANS, LA.	93.75	3.16	1.36	.65	.66	.00	.42	0.00		1072	.612
29	NEW YORK CITY	94.52	3.29	0.73	.26	.10	.09	.70	0.31		1049	.592
30	OKLAHOMA CITY, OKLA.	89.57	6.31	1.36	.36	.00	.00	.13	2.06	.21 O_2	1080	.615
31	OMAHA, NEB.	80.46	6.30	2.59	.68	.09	.05	.17	9.32	.34 He	1020	.668
32	PARKERSBURG, W. VA.	94.50	3.39	0.68	.12	.07	.03	.67	0.41	.01 O_2	1049	.592
33	PHOENIX, ARIZ.	87.37	8.11	2.26	.13	.00	.00	.61	1.37		1071	.633
34	PITTSBURG, PA.	94.03	3.58	0.79	.28	.07	.04	0.80	0.40	.01 O_2	1051	.595
35	PROVIDENCE, R.I.	93.05	4.01	1.02	.34	.08	.08	1.00	0.42		1057	.601
36	PROVO, UTAH	91.40	3.95	0.84	0.39	.03	.01	0.52	2.86		1032	.605
37	PUEBLO, COLO	73.86	5.71	3.20	1.34	.14	.06	.13	15.26		980	.706
38	RAPID CITY, S.D.	90.60	7.20	0.82	0.19	.03	.03	.18	0.93	.02 He	1077	.607
39	ST. LOUIS, MO.	93.32	4.17	0.69	.19	.05		.98	0.61			
40	SALT LAKE CITY, UTAH	91.17	5.29	1.69	.55	.16	.03	.29	0.82		1082	.614
41	SAN DIEGO, CALIF.	86.85	8.37	1.86	.15	.00	.00	.41	2.32	.04 He	1079	.643
42	SAN FRANCISCO, CALIF.	88.69	7.01	1.93	.28	.03	.00	.62	1.43	.01 He	1086	.624
43	TOLEDO, OHIO	93.54	3.58	0.66	.22	.06	.03	.85	1.11		1028	.594
44	TULSA, OKLA	86.29	8.36	1.45	.18	.14	.01	0.23	2.95	.39 O_2	1086	.630
45	WACO, TEX.	93.48	2.57	0.89	.43	.17	.11	1.69	0.66		1042	.607
46	WASHINGTON, D.C	95.15	2.84	0.63	0.24	.05	.05	0.62	0.42		1042	.586
47	WICHITA, KAN.	79.62	6.40	1.42	1.12	.48	.14	.10	10.62	0.10 O_2	1051	.660
48	YOUNGSTOWN, OHIO	93.30	3.49	0.69	0.18	0.04	0.00	0.50	1.80		1037	0.600

(1) AVERAGE ANALYSES OBTAINED FROM THE OPERATING UTILITY COMPANY(S) SUPPLYING THE CITY. THE GAS SUPPLY MAY VARY CONSIDERABLY FROM THESE DATA--ESPECIALLY WHERE MORE THAN ONE PIPELINE SUPPLIES THE CITY. ALSO, AS NEW SUPPLIES MAY BE RECEIVED FROM OTHER SOURCES. THE ANALYSES MAY CHANGE. PEAK SAVING (IF USED) IS NOT ACCOUNTED FOR IN THESE DATA.

(2) GROSS OR HIGHER HEATING VALUE AT 30 IN. HG. 60°F. DRY. TO CONVERT TO A SATURATED BASIS DEDUCT 1.73 PERCENT, I.E., 17.3 FROM 1000. 19 FROM 1100.

(3) 1954 DATA

(4) 1981 DATA (Ref. A-1).

The compressibility factor of NG at the usual storage tank pressure of 2400 psi is 1.5 percent lower than for methane, as indicated in Figure A-1, which covers the entire pressure range of interest. The curves are based on standard data and calculation procedures found in Reference A-4. The definition of compressibility factor is:

$$Z = \frac{PV}{NR_o T} \qquad \text{(A-1)}$$

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Table A-2. Natural Gas Composition and Heating Value--Pipeline Specifications and Southern California Supply

CONSTITUENT	PIPELINE SPECIFICATIONS(1)	SO. CALIF. SUPPLY (2)
HHV, BTU/SCF, MIN.	950-1000	1030-1080
H_2O, LB/MMSCF, MAX.	6-7	7
H_2S, GR/CSCF, MAX.	0.25-1.0	0-0.25
TOTAL S, GR/CSCF, MAX.	5-20	0.03-0.5
CO_2, VOL. %, MAX.	1-3	0.5-3
CO, VOL. %, MAX.	NA	NEGLIGIBLE
O_2 VOL. %, MAX.	0.2-2	0-0.2
N_2, VOL. %, MAX.	NA	0-2
H_2, VOL. %, MAX.	NA	0-2
HE, VOL %, MAX.	NA	0-0.04

(1) PIPELINE COMPANY RANGE OF CONTRACT SPECIFICATIONS. DATA FROM 1957, GIVEN IN REF. A-2.

(2) GAS SUPPLIED TO CUSTOMERS BY SOUTHERN CALIFORNIA GAS COMPANY (REF. A-3).

Table A-3. Typical Natural Gas Composition

CONSTITUENT	AMOUNT, VOL. %
METHANE	94.5%
ETHANE	3.1
PROPANE	0.4
N-BUTANE	0.2
NITROGEN	1.8
TOTAL	100.0%

Table A-4. Properties of Methane and a Typical Natural Gas

PROPERTY	METHANE	NATURAL GAS
MOLECULAR WT, G/MOLE	16.043	16.889
DENSITY, LB/SCF @14.696 PSIA, 60°F	0.04238	0.0445
LOWER HEATING VALUE,		
BTU/SCF	912	926
BTU/LB	21.520	20.800
HIGHER HEATING VALUE,		
BTU/SCF	1012	1024
BTU/LB	23.880	23.000
COMPRESSIBILITY FACTOR		
@ 0 PSIG, 60°F	0.998	0.998
@ 2400 PSIG, 70°F	0.790	0.778

where P is the gas pressure in psia, V is the volume in cubic feet, N is the number of lb-moles (i.e., W/M, where W is the gas weight in lb and M is the mean molecular weight), T is the temperature in ^{o}R, and R_o is the universal gas constant (10.73 psia ft^3/mole-^{o}R).

Under standard pressure (P_s = 14.7 psia) and temperature (T_s = 520^{o}R) conditions, 1 scf of gas contains the following weight of gas, W_s, equal to its density in lb/scf:

$$W_s = \left(\frac{P_s}{R_o T_s} \quad \frac{M}{Z_s}\right) \qquad \text{(A-2)}$$

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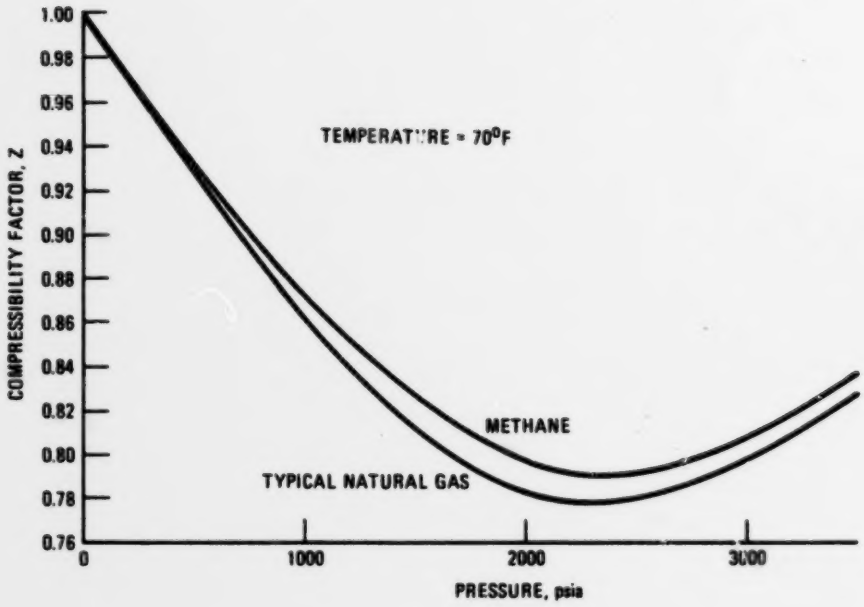

Figure A-1. Natural Gas Compressibility Factor at 70°F (Ref. A-4)

The tank contents at elevated pressure, in scf, is given by:

$$\frac{W}{W_s} = \frac{PVM}{ZR_oT}\left(\frac{R_oT_s}{P_s}\right)\frac{Z_s}{M} = \left(\frac{P}{P_s}\right)\frac{T_sZ_s}{TZ}V \qquad \text{(A-3)}$$

For $T = T_s$ and $Z_s = 0.998 \approx 1$,

$$\frac{W}{W_s} = 0.0679\ \frac{PV}{Z} \qquad \text{(A-4)}$$

The quantity of CNG (in scf) and the total stored energy in a tank are sensitive to the gas composition. For the typical NG of Table A-4, at 2400 psi and 70°F, the number of scf is greater than with methane by 1.5 percent, and the energy per scf is greater by 1.2 percent, for an

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energy storage advantage of about 2.7 percent. The composition used in Reference A-5 for determination of energy consumption by most CNG users is calculated to have an energy per scf advantage of 5.7 percent and an scf advantage of 4.6 percent, for a cumulative energy storage advantage of 10.6 percent compared to methane. It is evidently important to know both the composition of the NG being used, as well as its heating value, to estimate the energy storage capacity of a gas cylinder. The potential use of synthetic (or substitute) natural gas (SNG), landfill gas, municipal sewage treatment gas, etc., may also change this capacity.

A.2 LNG COMPOSITION

The composition of LNG varies over a considerable range, and depends on the origin of the NG feed, the degree of gas processing prior to liquefaction, the liquefaction process used, and the degree of "aging" of the LNG in the storage tank. A few examples of these effects on composition are as follows.

Gas from the Kenai Peninsula in Alaska is nonassociated, and thus is high in methane with essentially no natural gas liquids (NGL). It is liquefied and sent to Japan without processing, except for drying and carbon dioxide (CO_2) removal; a typical analysis is presented in Table A-5 (Ref. A-6). North Slope gas, on the other hand, is associated and therefore contains significant amounts of heavy hydrocarbons (HC). Reference A-7 presents an analysis of such gas, and the LNG that could be made from it, as shown in Table A-6. These data assume that no NGL is removed prior to liquefaction. The State of Alaska may require that NGL be recovered to serve as the basis for a petrochemical complex in the state (Ref. A-8). In this case, the LNG composition would approach that produced in the lower 48 states, which is discussed later. LNG from Algeria has also been low in methane content to date, due to inclusion of heavier components. A typical analysis is shown in Table A-7 (Ref. A-9). With regard to peak-shaving-plant LNG in the lower 48 states, two compositions were obtained. One of these, from the Northern Natural Gas Co. in Omaha, is given in Table A-8 (Ref. A-10).

Table A-5. Analysis of Kenai Peninsula LNG (Ref. A-6).

CONSTITUENT	AMOUNT, VOL. %
METHANE	99.72%
ETHANE	0.07
PROPANE OR HEAVIER	0.01
NITROGEN	0.20
TOTAL	100.00%

NOTE: HHV = 1008 BTU/SCF

Table A-6. Analysis of North Slope Pipeline Gas and LNG (Ref. A-7)

CONSTITUENT	AMOUNT, VOL. %	
	PIPELINE GAS	LNG
METHANE	85.91%	86.66%
ETHANE	7.77	8.37
PROPANE	3.93	4.25
ISOBUTANE	0.26	0.28
NORMAL BUTANE	0.30	0.32
ISOPENTANE	0.03	0.03
NORMAL PENTANE	0.02	0.02
HEXANE PLUS	0.01	0.01
NITROGEN	0.75	0.06
CARBON DIOXIDE	1.02	0.00
TOTAL	100.00%	100.00%

NOTE: HHV = 1158 BTU/SCF

This analysis is for LNG entering the storage tank. If the liquid is held for a considerable period and the boiloff is vented, nitrogen (N_2) and lighter HC will decrease in concentration and the heavier components will increase. As an example, N_2 amounts to about a third of a percent after several months in storage.

Table A-7. Analysis of Algerian LNG (Ref.A-9)

CONSTITUENT	AMOUNT, VOL. %
METHANE	86.98%
ETHANE	9.35
PROPANE	2.33
BUTANE	0.63
NITROGEN	0.71
TOTAL	100.00%

NOTE: HHV = 1123 BTU/SCF

Table A-8. Analysis of Northern Natural Gas Company LNG (Ref. A-10)

CONSTITUENT	AMOUNT, VOL.%
METHANE	93.32%
ETHANE	4.65
PROPANE	0.84
ISOBUTANE	0.05
NORMAL BUTANE	0.11
ISOPENTANE	0.01
NORMAL PENTANE PLUS	0.01
NITROGEN	1.01
TOTAL	100.00%

NOTE: HHV = 1052 BTU/SCF

A typical LNG composition from San Diego Gas and Electric Company is presented in Table A-9 (Ref. A-11). It was stated that the LNG composition varies somewhat during the year as the gas sources change and as gas is taken from underground storage.

Table A-9. San Diego Gas and Electric Company
LNG Composition (Ref. A-11)

CONSTITUENT	AMOUNT, VOL. %
METHANE	92%
ETHANE	6
PROPANE PLUS	1
NITROGEN	1
TOTAL	100%

NOTE: HHV = 1060 BTU/SCF

A.3 NG HYDRATES

NG is dehydrated before entering transmission lines to prevent corrosion and "freeze-ups" due to hydrate formation. To be effective, enough water must be removed so that the dew point will not be reached at the lowest operating temperature and maximum pressure of the system. Some of the early techniques for dehydration did not achieve this goal, and flow stoppages due to hydrate formation were frequent. At first, it was assumed that the freezing was due to ice formation, and that the gas temperature reached 32°F or lower somewhere along the pipeline. It was not until the mid-1930s that it was realized that "freezing" was caused by hydrate formation, and could occur at temperatures above 32°F. Although modern dehydration methods usually prevent freeze-ups, water occasionally finds its way into the system as a result of defective equipment or other operational problems. This discussion briefly covers the main characteristics of the hydrates and techniques to predict their formation.

The term "gas hydrate" has been applied for nearly a century to the solids that are formed by the combination of many gases with an excess of water under pressure. Years of research have revealed that a large number of gases form hydrates and so do many liquids. These solid hydrates represent one form of chemical inclusion structures termed "clathrates." In these clathrates, the water molecules are linked together and

form either spherical structures or cages which trap the gas. A few compounds, such as cyclopropane, form hydrates of both types (Ref. A-12).

It should be emphasized that there is no chemical bond between water and the typical components of NG; the latter only occupy the physical voids within the cages. Therefore, it is possible to have double or mixed hydrates. Also, the water clathrates are nonstoichiometric, although the composition variability is constrained by the minimum cage occupancy necessary for thermodynamic stability of the lattice and by the maximum occupancy representing complete filling of the structure. In the case of methane, there are at most about six molecules of the gas in the 46-molecule water structure, corresponding to a methane weight fraction of 10.4 percent (Ref. A-13).

As already indicated, the hydrate-forming gases are very diverse, including inert gases, saturated and unsaturated HC, halogens and halogen-substituted HC, hydrogen sulfide, oxygen, carbon dioxide and many others. Among the paraffin HC, methane, ethane, propane, and iso-butane form hydrates, but normal butane takes part in hydrate formation only in a mixture with smaller molecules. The larger molecules generally form more stable hydrates, thus methane is the least stable of the NG constituents. Gas hydrates obtained from pipelines look much like packed snow. They are very light and porous and burn quietly, leaving a small water residue. They melt under pressure reduction and/or temperature increase.

There is no simple way to predict hydrate formation with certainty, but there are several methods for estimating whether hydrate formation is possible. For example, Figure A-2 shows the minimum pressure required to form a hydrate at various temperatures. A typical NG at 70°F would require a pressure of at least 2500 psi to form a hydrate. In addition, the gas would need to contain more than 15 pounds of water per million scf (greater than 340 ppm), which is its saturated moisture content. In other words, free water must be present to form hydrates. There is no certainty that hydrates will form immediately when the necessary pressure-temperature-moisture conditions are reached. Different

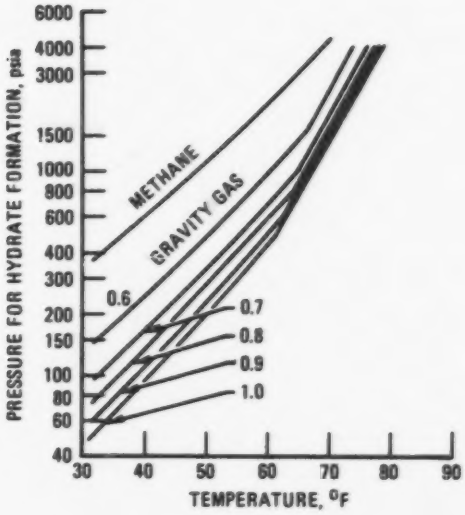

Figure A-2. Pressure-Temperature Curves for Predicting Hydrate Formation (Ref. A-14)

conditions, or innoculation with a small crystal of the hydrate, are sometimes necessary to initiate formation (Ref. A-13).

Figure A-3 is also useful in predicting hydrate formation, or in ensuring avoidance of hydrates. The plot shows the minimum initial gas temperature that will allow adiabatic throttling of NG between two pressures without hydrate formation. It indicates that expansion from 2400 psi in a vehicle cylinder to a depleted state of about 100 psi tends to promote hydrate formation if the initial temperature is under 140°F, if the NG is saturated, and if expansion occurs rapidly enough to approximate adiabatic conditions. However, if the NG is sufficiently dry, the initial gas temperature may be below the minimum without incurring hydrate formation.

The most effective procedures to prevent hydrate formation are to dehydrate the NG, or to add an inhibitor to lower the formation temperature. Addition of chemicals that lower the freezing point of water causes a similar reduction in the temperatures at which hydrates

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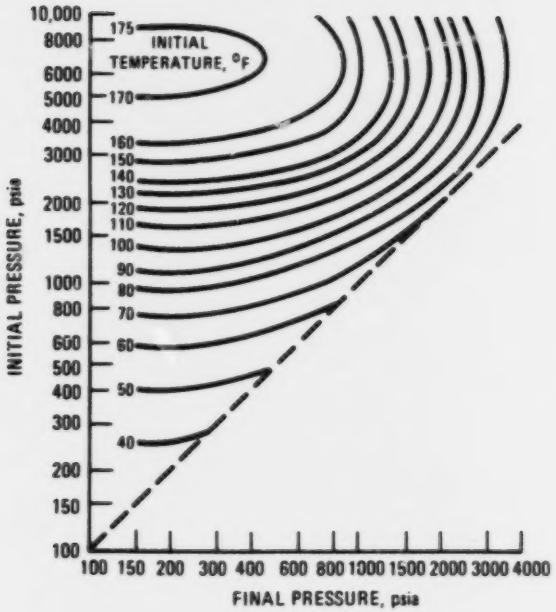

Figure A-3. Permissible Initial Gas Temperatures for Adiabatic Expansion of a 0.6-Gravity NG without Hydrate Formation (Ref. A-14)

will form. Thus, an antifreeze such as methanol may be used to prevent hydrate stoppage of gas lines, pressure regulators, and mixing valves in situations where dehumidifying the gas is not practical. Field gathering lines, small distribution systems, and systems where hydrate formation is infrequent or of short duration are examples of situations where inhibitors may be used. Methanol is typically injected between the CNG compressor and the cascade storage tanks, which operate at pressures up to 3600 psia in CNG fueling stations.

A recent attempt by the city of Stillwater, Oklahoma, to utilize NG gas from an oil well as the fuel for its fleet of CNG vehicles proved unsuccessful because of excessive formation of hydrates during the compression process. This problem was attributed to contaminants in the gas and a propane content of about 8 percent. The Stillwater fleet is now operating on normally distributed NG (Ref. A-15).

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A.4 AUTOIGNITION TEMPERATURE

A parameter warranting additional discussion is the autoignition temperature (AIT). Tabulated values for the gaseous fuels and methanol are substantially higher than for current petroleum fuels. The significance of these differences to operation of SI and CI engines, and to fuel safety, are discussed in this subsection.

The AIT of a fuel is the temperature required to initiate self-sustained combustion in the presence of air and in the absence of a spark or flame (Ref. A-16). AIT is also termed the self-ignition temperature and the spontaneous ignition temperature (Refs. A-17 and A-18). The AIT is not an absolute property, and all AIT data must be interpreted carefully in the context of the specific test method and conditions. Unfortunately, such attendant information is seldom furnished in the literature.

Two types of AIT are typically reported, depending upon whether the objective is to cause or to prevent ignition. The first type is generally obtained at high temperatures, and reflects a relatively short ignition delay. Conversely, the minimum AIT is usually reported in the safety literature. In this case, the combustible material and air can remain in contact for an extended period prior to ignition (Ref. A-19). The two AIT regimes are related through an Arrhenius- or Semenov-type equation of the form:

$$\log t = (A/T) + B \qquad \text{(A-5)}$$

where t is the ignition delay time, T is the absolute (°K or °R) autoignition temperature, and A and B are constants. Thus, a plot of the logarithm of the ignition delay versus the reciprocal of the absolute temperature should yield a straight line, with the two types of ignition data represented by the upper and lower extremes of the line. However, there are no accepted time criteria delimiting the two ignition regimes and, in fact, the ignition time lag is seldom specified in conjunction with the AIT value (Ref. A-20).

In addition to the time factor, ignition measurements depend on the type and size of the apparatus used, the air-fuel ratio, and the mixture pressure. For liquid fuels, droplet size is also a factor. Finally, different values are obtained for stagnant and flowing air systems. There is a relative scarcity of high-temperature, short-delay ignition data pertinent to internal combustion engines. This is due to the practical difficulty of rapidly (0.1 to 1.0 msec) creating an initial mixture at a high temperature (Ref. A-21).

AIT values in the literature range from 428°F to 950°F for gasoline, 999°F to 1350°F for methane, and 725°F to 878°F for methanol. Most of the data sources do not provide the associated ignition delays. In References A-21 and A-22, there are graphical data relating methane ignition temperature and ignition delay; in Reference A-21, actual data points are not shown and, as noted, all curves are extrapolated. Methane ignition delay versus ignition temperature from these sources is shown in Figure A-4, for near atmospheric pressure. It appears that most of the reported values, up to 1350°F, are for ignition delays of 1 second or more, and thus more related to safety than to combustion in an engine. In Reference A-18, it is noted that ignition conditions in the test apparatus are substantially different from those within an engine cylinder.

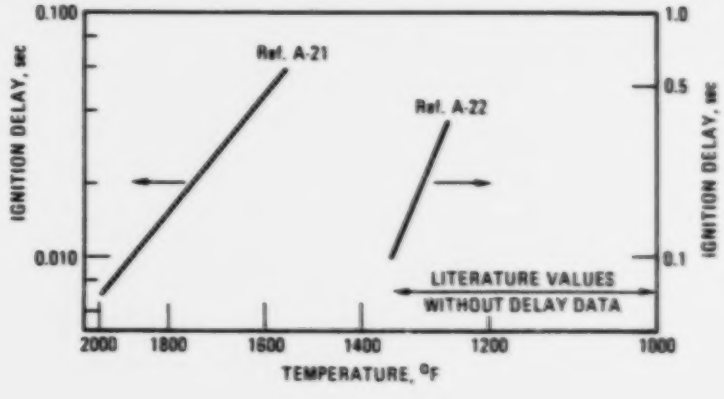

Figure A-4. Methane Ignition Delay versus Temperature

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The primary engine-related use of AIT data has been in attempting to explain knock in terms of ignition temperature and ignition delay. To date, this has met with only limited success. Probably Obert says about as much as can be safely said in this regard: "The knock ratings of the fuels are in rough proportion to the self-ignition temperatures" (Ref. A-17).

AIT finds its most important application in safety work. Values of AIT used in the area of fire prevention are normally the lowest reported, to provide the greatest margin of safety. If the lowest AIT temperatures given previously for each of the fuels are compared, methane appears to be the safest material to handle.

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APPENDIX B

OPERATING CHARACTERISTICS OF CNG, LNG, AND METHANOL VEHICLES

APPENDIX B

OPERATING CHARACTERISTICS OF CNG, LNG, AND METHANOL VEHICLES

This appendix examines fuel economy, performance, and emissions test data for natural gas (NG)- and methanol-fueled vehicles. Baseline gasoline and compressed natural gas (CNG) vehicle tests were performed at the Environmental Protection Agency's (EPA's) Ann Arbor Motor Vehicle Emission Laboratory as part of this study, using two late-model automobiles. Additional data were acquired from the open literature, NG equipment manufacturers, and fleet operators. With few exceptions, these vehicles were equipped with dual-fuel systems. As discussed in Volume II, dual-fuel capability limits the fuel economy and power output of NG and methanol vehicles by not fully exploiting the high octane number of these fuels.

A substantial effort was made to acquire data on user experience with NG-fueled vehicles. In this regard, discussions were held with Atlanta Gas Light Company, currently the only fleet user of liquefied natural gas (LNG), and the following 18 users of CNG systems.

(1) ARA, Inc., Philadelphia, Pennsylvania

(2) Battle Creek Gas Company, Battle Creek, Michigan

(3) City of Brewton, Alabama

(4) City of Coalinga, California

(5) Eaton School District No. 2, Eaton, Colorado

(6) City of Fort Collins, Colorado

(7) Gas Service Energy Corporation, Kansas City, Missouri

(8) City of Greeley, Colorado

(9) Michigan Consolidated Gas Company

(10) Mid-Peninsula Cab Company, Redwood City, California

(11) Pacific Northwest Bell Telephone Co., Seattle, Washington

(12) Salt Lake City, Utah

(13) Sedgwick County, Wichita, Kansas

(14) Shawnee County, Kansas

(15) Southern California Gas Company, Los Angeles, California

(16) City of Stillwater, Oklahoma

(17) Washington Gas Light Company, Springfield, Virginia

(18) Yellow Cab Company of North Orange County, Inc., Anaheim, California

To date, few users have devoted great effort toward quantification of changes in fuel economy, performance, and emissions resulting from conversion to NG. However, the transportation department of the City of Fort Collins, Colorado, expressed concern about emissions, and plans a city driving cycle evaluation at the Colorado State University. (Ref. B-1).

B.1 CNG VEHICLE OPERATING EXPERIENCE

Interest in dual-fuel CNG applications has been increasing during the last 15 years. During that time, a number of companies, municipalities, and governmental agencies in the United States and abroad have converted some or all of their spark-ignition (SI) fleet vehicles to CNG, primarily for economic reasons. Fuel economy, performance, and emissions data acquired from 12 such organizations are presented in the following subsections. These organizations are: (1) ARA, Inc., (2) Battle Creek Gas Company, (3) Eaton, Colorado, School District, (4) General Services Administration, (5) City of Greeley, Colorado, (6) Michigan Consolidated Gas Company, (7) Sedgwick County, Kansas, (8) Shawnee County, Kansas, (9) Southern California Gas Company, (10) Washington Gas Light Company, (11) Wellington Gas Company, New Zealand, and (12) Yellow Cab Company of San Rafael, California.

CNG users generally adjust their converted vehicles for optimum fuel economy or power. Baseline fuel economy is often that of the pre-conversion vehicle. Changes in spark timing and air-fuel ratio at conversion affects both fuel economy and exhaust emissions. Few users have measured post-conversion exhaust emissions. Most emission results that are available come from older tests that used non-dispersive infrared (NDIR) equipment for hydrocarbon (HC) measurements. Since 1975, the Environmental Protection Agency (EPA) has required flame ionization detectors (FID) for HC measurement. Relative to the FID method, the NDIR method underestimates HC emissions by a factor of about 2, and is particularly insensitive to methane, the principal exhaust HC component of CNG-fueled vehicles.

It should be noted that accurate determination of the fuel economy of in-use CNG vehicles is not always possible because of limitations in the available data. For example, CNG fuel consumption is frequently determined by means of a relatively imprecise onboard pressure gauge in combination with a fuel density chart that may not accurately reflect local fuel properties. Also, gasoline and CNG mileage are often measured under different ambient conditions and driving cycles. For example, there is a tendency for operators to switch to gasoline for high-load operation such as hill climbing or carrying large payloads. One user has instructed his drivers to operate on gasoline on the highway because CNG consumption is higher there than in urban operation, according to his limited test experience (Ref. B-2). Finally, the fuel energy equivalency factor of NG is not always known accurately, and it can vary with time for a given fleet.

B.1.1 ARA, Inc.

ARA, Inc. is currently converting a large number of its vehicles to CNG operation. ARA vehicles typically are used for mobile food service, uniform rentals, and distribution and delivery of rental items in urban areas. Their duty cycles can be characterized as primarily transient and part-throttle under medium to heavy loads. Table B-1 presents pre-conversion gasoline and post-conversion CNG fuel economy data for six

step-vans, which range from 1966 to 1981 models and include 4-, 6-, and 8-cylinder engines (Refs. B-3 and B-4). These vehicles typically accumulate more than 90 percent of their total mileage on CNG (Ref. B-4). In the absence of detailed fuel properties, fuel economy on CNG was computed from ARA cost and mileage information provided in the data source (Ref. B-2), using two fuel equivalency factors, 100 scf/gal and 126 scf/gal, that represent the range of CNG properties. ARA assumes the 100 scf/gal factor, while average NG properties indicate 126 scf/gal. Based on the 100 scf/gal equivalency factor used by ARA, the fleet averages about 10 percent higher fuel economy on CNG than on gasoline. Individual vehicles range from a 7 percent loss to a 36 percent gain. The 126 scf/gal equivalency factor produces a fleet average fuel economy of 11.3 mpg_e, which is 38 percent higher than gasoline, with individual vehicle gains ranging from 17 percent to 71 percent. Although the duty cycle of these vehicles suggests that reduced throttling losses might improve engine efficiency, the large fuel economy increases cannot be explained by that effect alone. However, all ARA vehicles operate with advanced spark timing and are retuned frequently for maximum fuel economy (Ref. B-4). Power loss is estimated by ARA at 10 percent, and is not considered to be a problem, except during hill climbing with heavy loads (Ref. B-5). Emissions after conversion are not known.

Table B-1. Fuel Economy of Six ARA, Inc. Step Vans with Gasoline and CNG (Ref. B-3)

	EQUIVALENT FUEL ECONOMY, MPG_E		
VEHICLE	GASOLINE	CNG (COMPUTED)	
NUMBER	BASELINE	@100 SCF/GAL	@126 SCF/GAL
1	6.4	7.9	10.0
2	7.6	8.1	10.2
3	9.4	12.8	16.1
4	8.9	10.2	12.9
5	7.8	7.2	9.1
6	9.0	8.9	11.2
AVERAGE	8.2	9.0	11.3

B.1.2 Battle Creek Gas Company

Fuel economy data developed over a 12-month period by the Battle Creek (Michigan) Gas Company for its fleet of dual-fuel light-duty and medium-duty vehicles are shown in Figure B-1 (Ref. B-6). For operation on gasoline, the average fuel economy is 9.6 mpg, and for CNG the fuel economy is 8.7 mi/ccf. Based on a lower heating value (LHV) of 890 Btu/scf, derived from the higher heating value (HHV) of 990 Btu/scf provided by Battle Creek Gas Company, the equivalent fuel economy for CNG is 11.3 mpg_e, which is approximately 17 percent higher than measured for gasoline. Spark timing was advanced to varying degrees with CNG, which may explain part of the fuel economy increase. Pre- and post-conversion gasoline fuel economies are comparable (Ref. B-7). No data are available concerning relative emissions, power, or acceleration times.

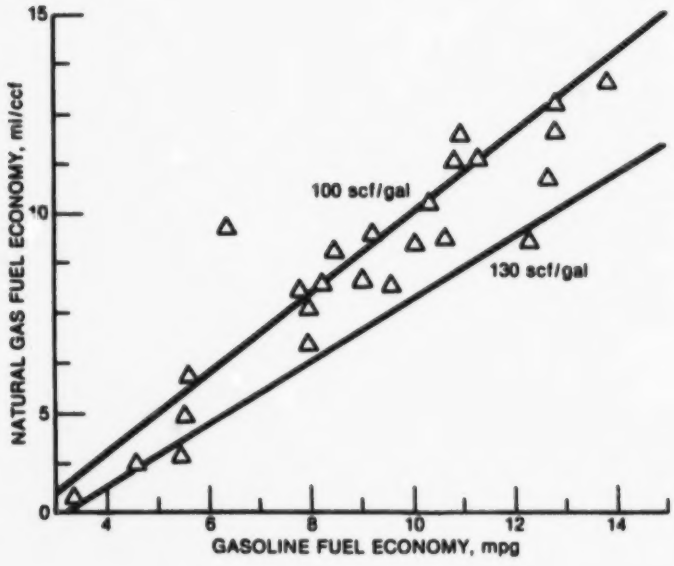

Figure B-1. Fuel Economy of Battle Creek Gas Company Light-Duty and Medium-Duty Vehicles (Ref. B-6)

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B.1.3 Eaton School District

The School District of Eaton, Colorado, has converted 13 of its buses to dual-fuel operation. The fleet ranges from 1969 to 1979 models, and encompasses a variety of makes, engines, and transmissions (Ref. B-8). Table B-2 presents pre-conversion gasoline and post-conversion CNG fuel economy for 11 buses, as estimated by the District. The CNG data have been converted to gasoline equivalent values using two assumed fuel energy equivalency factors, in the absence of fuel property data. CNG fuel economy is the gasoline equivalent of 6.0 mpg_e, based on the 126 scf/gal equivalency factor. This is a 31 percent gain over the 4.6 mpg pre-conversion gasoline fuel economy. For the conversion, spark timing was advanced by 3 to 5 degrees from the stock setting, and the air-fuel ratio was adjusted to restore engine power (Ref. B-9). On average, a timing advance of this size would be expected to increase CNG fuel economy by 3 to 5 percent. No emissions, power, or acceleration data are available for these vehicles.

Table B-2. Fuel Economy of Eaton School District Bus Fleet (Ref. B-8)

BUS NUMBER	MODEL YEAR	EQUIVALENT FUEL ECONOMY, MPG_E BASELINE GASOLINE	CNG (COMPUTED) @100 SCF/GAL	CNG (COMPUTED) @126 SCF/GAL
8	1969	5.3	4.6	5.8
10	1969	3.9	5.0	6.3
1	1970	4.7	6.0	7.6
12	1970	5.6	6.3	7.9
20	1972	5.0	5.3	6.7
5	1973	4.5	4.2	5.3
7	1973	4.1	4.1	5.2
11	1974	4.4	5.1	6.4
14	1974	4.0	3.3	4.2
3	1978	4.7	3.4	4.3
4	1979	4.4	5.4	6.8
AVERAGE		4.6	4.8	6.0

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B.1.4 General Services Administration

In 1969, the General Services Administration (GSA) tested a fleet of eight pairs of 1968 and 1969 model year sedans and light-duty trucks, and four pairs of older medium-duty trucks (Ref. B-10). One vehicle from each pair was converted to CNG operation. Basic spark timing was not changed, but the vacuum advance was deactivated, and the mixture was adjusted to a 25 percent excess air factor (0.8 fuel-air equivalence ratio). The principal objective was to demonstrate lower emissions with CNG.

Emissions of hydrocarbons (HC), carbon monoxide (CO), and oxides of nitrogen (NO_x) over the seven-mode driving cycle for the gasoline control vehicles and the CNG vehicles are shown in Figures B-2 through B-4 (Ref. B-10). GSA adjusted the measured HC emissions for CNG downward by a factor of 2 to account for the lower HC reactivity relative to operation on gasoline. As shown in Figures B-2 through B-4, the emissions reductions of the automobiles with CNG are 84 percent for HC, 79 percent for CO, and 65 percent for NO_x. While these reductions are substantial, the emissions of the control vehicles are high relative to current vehicle standards. Emission data from the converted vehicles while operating on gasoline are not available.

Table B-3 summarizes fuel economy and performance data for the fleet. Although the control and converted vehicles had been selected at random, the data indicate that the converted vehicles have gasoline fuel economies which are consistently lower than their control vehicle counterparts. The converted vehicle fleet average fuel economy with gasoline is 7.8 mpg, only 74 percent of the control average of 10.5 mpg. The change may be due to the fact that the converted vehicles lacked vacuum spark advance and weighed more. The HHV values for gasoline and CNG taken from Reference B-10 yield a fuel energy equivalency factor of 119.6 scf/gal. The CNG fuel economies for the sedans, trucks, and combined light-duty vehicles are 11.2, 13.1, and 11.7 mpg_e, respectively, which are 43, 74, and 50 percent above the respective converted vehicles and 6, 25, and 11

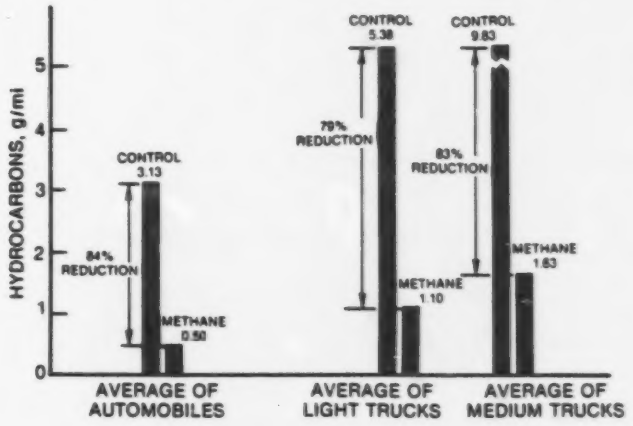

Figure B-2. Hydrocarbon Emissions of GSA Vehicles Using Gasoline and CNG (Ref. B-10)

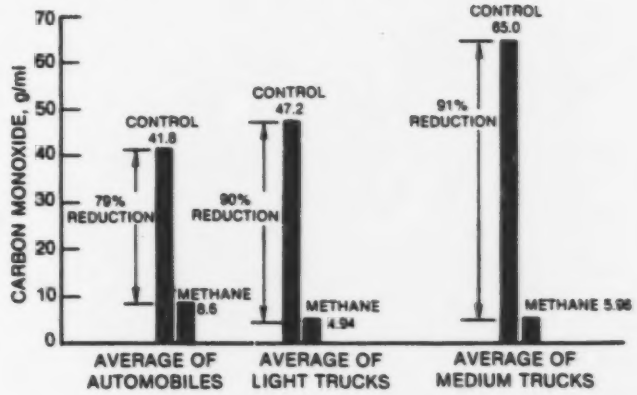

Figure B-3. Carbon Monoxide Emissions of GSA Vehicles Using Gasoline and CNG (Ref. B-10)

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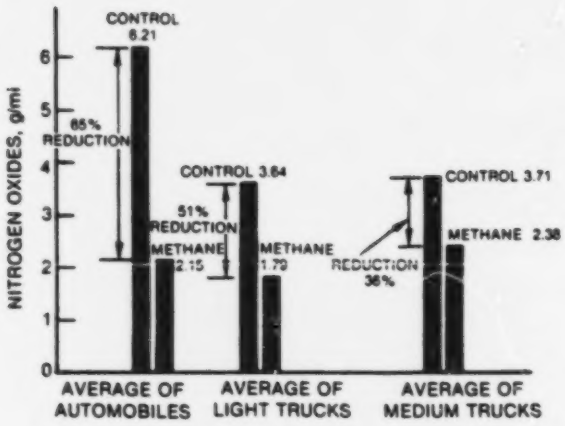

Figure B-4. Oxides of Nitrogen Emissions of GSA Vehicles Using Gasoline and CNG (Ref. B-10)

Table B-3. Fuel Economy and Acceleration of GSA Light-Duty Vehicles with Gasoline and CNG (Ref. B-10)

	FUEL ECONOMY				INCREASE IN 15-50 MPH ACCEL. TIME,
	CONTROL VEHICLE	CONVERTED VEHICLE W/GASOLINE	CONVERTED VEHICLE WITH CNG		
VEHICLE	MPG	MPG	MI/CCF	MPG_E (1)	PERCENT
SEDANS					
'68 CHEVROLET	10.8	9.1	12.4	14.8	50%
'68 CHEVROLET	12.1	8.7	10.5	12.6	18
'69 FORD	10.2	7.1	8.3	9.9	48
'69 FORD	8.7	6.3	8.2	9.8	80
AVERAGE	10.5	7.8	9.3	11.2	49
TRUCKS					
'69 PICKUP	8.3	5.8	10.9	13.1	32
'69 CARRYALL	12.5	6.1	11.1	13.2	60
'69 PICKUP	10.0	8.3	10.5	12.6	38
AVERAGE	10.5	7.5	10.9	13.1	43
COMBINED AVG.	10.5	7.8	9.8	11.7	47

(1) BASED ON HHV OF 128,000 BTU/GAL FOR GASOLINE AND 1070 BTU/SCF FOR CNG (FUEL ENERGY EQUIVALENCY FACTOR OF 119.6 SCF/GAL).

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percent above the respective control vehicles. The increase in CNG fuel economy may partly be attributed to reduced engine throttling losses and engine operation at leaner air-fuel ratios. This is particularly evident in the light-duty trucks, which typically operate at higher loads. However, at wide-open throttle (WOT), the inherent power loss with CNG caused a 47 percent average increase in WOT acceleration times, with individual vehicles showing increases from 20 to 80 percent relative to gasoline. Based on the computer simulations of Section B.3.2.4, this observed loss in acceleration performance suggests engine power losses of about 15 to 40 percent.

B.1.5 City of Greeley

The City of Greeley, Colorado, recently converted 90 vehicles to CNG operation, and has provided fuel economy data based on an assumed fuel equivalency factor of 100 scf/gal. Based on the available data, the Public Works department has concluded that the fleet fuel economy with CNG, relative to gasoline, is approximately 0.75 mpg_e higher in city driving, and about 1.0 mpg_e lower on the highway. A Plymouth Fury with a V-8 engine, which was one of the first vehicles converted, has averaged 12.1 mpg with gasoline and 12.6 mpg_e with CNG, for a 4.1 percent improvement (Ref. B-11).

B.1.6 Michigan Consolidated Gas Company

Michigan Consolidated Gas Company recently reported the results of acceleration tests and in-use fuel economy measurements for two dual-fuel 1/2 ton pick-up trucks (Ref. B-12). As shown in Table B-4, acceleration times with CNG consistently increase relative to gasoline. The increases suggest CNG power losses of about 15 and 20 percent for advanced and stock spark timing, respectively, which is consistent with data provided by other sources. Table B-5 shows the fuel economy of these trucks when operated with standard spark timing. The gasoline and CNG heating values of Reference B-12 yield a fuel energy equivalency factor of 125.1 scf/gal. The resulting average CNG fuel economy improvement is only about 0.2 mpg_e, or 2 percent higher than the gasoline fuel economy. This is a

much smaller difference than normal variations in fuel economy measurement.

Table B-4. Change in Acceleration Times for Two Pick-Up Trucks Converted to CNG (Ref. B-12)

VEHICLE	SPARK TIMING, DEG. BTDC	INCREASE IN ACCEL. TIME RELATIVE TO STOCK, PERCENT 0 - 25 MPH GASOLINE	0 - 25 MPH CNG	0 - 50 MPH GASOLINE	0 - 50 MPH CNG
A	10	0	+38	0	+40
B	15	+12	+23	-1	+24

Table B-5. Fuel Economy of Two Pick-Up Trucks with Gasoline and CNG (Ref. B-12)

VEHICLE	FUEL ECONOMY GASOLINE BASELINE MPG	CNG MI/CCF	CNG MPG_E (1)
A	10.7	8.8	11.0 (+3%)
B	12.2	9.8	12.3 (+1%)

(1) BASED ON LHV OF 115,700 BTU/GAL FOR GASOLINE AND 925 BTU/SCF FOR CNG (ENERGY EQUIVALENCY FACTOR OF 125.1 SCF/GAL).

B.1.7 Sedgwick County

Sedgwick County, Kansas, has recently converted 85 vehicles to CNG, and has compared the fuel economy of several cars using two different makes of conversion kits, one of which is supplemented with a spark advance device to reduce power loss. In stop-and-go driving of a Ford LTD II with a 302 cubic inch displacement (CID) V-8 engine and a spark advance

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device, Sedgwick County found a fuel economy loss of 32 percent with CNG, based on their assumed fuel equivalency factor of 100 scf/gal. This loss is relative to the historical average fuel economy for the unmodified car on gasoline. At highway speeds of about 55 mph, five Ford cars equipped with CNG conversion kits, and operated with and without spark advance, showed an average fuel economy loss of 17 percent relative to gasoline, with individual vehicles ranging from a 4 percent gain to a 30 percent loss. The vehicles were refilled to 2400 psig, regardless of ambient temperature. This introduces considerable uncertainty into the calculation of CNG fuel economy (Ref. B-13).

B.1.8 Shawnee County

The Sheriff's Department of Shawnee County, Kansas, has recently evaluated the performance of two 1980 Ford LTD four-door sedans equipped with 302 CID V-8 engines. The pre-conversion year-round fuel economy of these cars was 14 to 15 mpg, compared to only 10 to 11 mpg_e with CNG in summer operation, with heavy air conditioning usage. This corresponds to a fuel economy loss of about 30 percent, of which an undetermined portion is due to air conditioning power consumption. (Ref. B-14).

B.1.9 Southern California Gas Company

Southern California Gas Company began converting light-duty and medium-duty vehicles to CNG in 1969. Initially, a number of problems were encountered, including excessive power loss, compressor system downtime, and lack of experienced mechanics. These problems have since been overcome by converting only vehicles with larger engines and higher axle ratios, and by improving maintenance procedures (Ref. B-15).

Dynamometer tests of six unidentified 1967 through 1969 model vehicles after 4000 miles of dual-fuel operation showed significant reductions in engine-out emissions when using CNG instead of gasoline (Ref. B-16). All CNG vehicles were calibrated for low emissions by using a fuel-air equivalence ratio of 0.8. One vehicle, tested in accordance with the hot-start 7-mode test procedure, achieved HC, CO, and NO_x emissions reductions of 58, 76, and 93 percent, respectively. All HC

measurements were made with NDIR instrumentation, which is relatively insensitive to methane. Five other vehicles were tested from a cold start for gasoline and a hot start for CNG, which precludes a reliable direct comparison of the test data. At the time of conversion, the approximate emission reductions were 40 to 80 percent for HC, and 40 to 90 percent for CO. After 4000 mi, the five-vehicle fleet averaged a 50 percent HC reduction, an 80 percent CO reduction, and a 62 percent NO_x reduction.

Average fuel consumption for the six-vehicle fleet was 7900 Btu/mi (14.4 mpg_e) with gasoline, and 7500 Btu/mi (15.2 mpg_e) with CNG, for an overall 5 percent gain with CNG. These figures are based on a specific gravity of 0.74 for gasoline, and LHV values of 114,000 Btu/gal for gasoline and 1000 Btu/scf for CNG (114 scf/gal energy equivalency factor) (Ref. B-16). Since the gasoline data are based on cold-start tests and the CNG data on hot-start tests, the true fuel economy gain with CNG is probably lower. The only vehicle with gasoline fuel economy (16.2 mpg) higher than CNG fuel economy (15.8 mpg_e) is the same one mentioned previously that had hot-start tests with both fuels.

B.1.10 Washington Gas Light Company

Based on the experience with 37 converted Dodge service vans, Washington Gas Light Company feels that 113 scf of NG is required to replace 1 gallon of gasoline in actual vehicle operation (Ref. B-17).

B.1.11 Wellington Gas Company

In a joint program conducted in 1977 and 1978, the Wellington Gas Company and the Auckland Gas Company, both of New Zealand, tested about 50 light-duty and medium-duty vehicles with gasoline and CNG. Test results from twenty 1966 to 1978 model year vehicles are summarized in a report to the New Zealand Energy Research and Development Committee (Ref. B-18). With spark timing settings of 8 to 12 degrees before top center (BTC), HC emissions were reduced by 10 to 80 percent relative to gasoline, and CO was reduced by 50 to 95 percent. Fleet average HC and CO reductions were about 45 percent and 75 percent, respectively. As reported elsewhere, NO_x was reduced by 50 percent (Ref. B-19). Baseline

emission levels were apparently higher than current emission standards. Power losses of 10 to 25 percent were measured on the dynamometer, with the highest losses occurring near closed throttle. Zero to 80 km/hr acceleration times of six vehicles increased by 5 to 34 percent with CNG, with a 20 percent average increase. One heavily laden vehicle experienced a 25 to 35 percent decrease in acceleration performance with CNG, while a similar unladen vehicle lost only 15 to 25 percent. Power loss at steady state for 6 vehicles was 0 to 48 percent with CNG, depending on engine speed and ignition timing. Average power loss was 18 percent. A capacitive discharge ignition (CDI) system was found to boost engine torque, particularly at part throttle.

In-use fuel economy data for the Wellington and Auckland fleets are shown in Figure B-5. Average gasoline fuel economy is 13.9 mpg, while average CNG fuel economy is 15.8 mpg_e, a 13 percent increase. The reported HHV for CNG of 1135 Btu/scf is considerably higher than that of the average NG available in the United States, while the reported HHV of 122,000 Btu/gal for gasoline is low by U.S. standards (Ref. B-18). Based on these values, the fuel equivalency factor is about 108 scf/gal. The Auckland fleet has two vehicles with significantly higher fuel economy on CNG than the fleet average. One is a small minivan with a 1 liter engine, and the second is a 1978 Chevette equipped with a CDI system. A short dashed line in Figure B-5 connects this vehicle to another Chevette with a standard ignition system, which lies very near the fleet trend line. The CDI-equipped Chevette has both lower gasoline fuel economy (18 versus 21 mpg) and higher CNG fuel economy (26 versus 22 mi/ccf) than its standard-ignition counterpart. The CDI-equipped Chevette was apparently optimized for CNG operation to the detriment of gasoline operation.

B.1.12 Yellow Cab Company

In 1973, the Yellow Cab Company of San Rafael, California, began converting some of its fleet vehicles to CNG, using Dual Fuel Systems, Inc., equipment (Ref. B-15). By 1977, 22 vehicles had been converted to dual-fuel operation. These vehicles averaged a total of 1.5 million miles

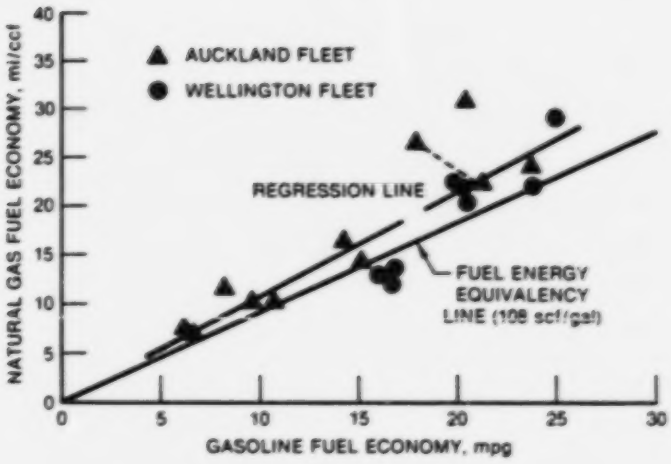

Figure B-5. Fuel Economy of Auckland and Wellington Fleets with Gasoline and CNG (Ref. B-.

annually, mostly using CNG. Although the equivalent fuel economy with CNG is only 11 mpg_e, which is 12 percent lower than reported with gasoline, significant fuel cost savings were realized. The source did not identify the basis for determining equivalent fuel economy. In addition, the use of CNG resulted in lower vehicle maintenance costs because the lubricating oil and spark plug change intervals could be extended significantly.

B.2 LNG VEHICLE OPERATING EXPERIENCE

Available data on the use of LNG in automotive applications are limited. In principle, the effects of CNG operation also apply to LNG. Normally, the liquid fuel is vaporized before combustion using coolant or exhaust system heat (Refs. B-20 through B-22). Alternatively, the heat of vaporization can be used to provide mixture cooling. This increases the engine's volumetric efficiency by increasing the mixture density and reduces the power losses generally experienced with CNG. For example, at a temperature of 0°F, a stoichiometric LNG mixture has about the same energy density as a stoichiometric gasoline mixture at 60°F. However, if both are at 60°F, LNG energy density is only about 90 percent of that of gasoline. In practice, substantial mixture cooling would require special precautions to prevent ice formation under cold and humid ambient conditions.

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The Atlanta Gas Light Company is currently operating the only LNG fleet identified in the course of this study. This fleet consists of over 100 dual-fuel vehicles, including sedans, vans, pickup trucks, and medium-duty trucks (Ref. B-23). About 120,000 miles are accumulated per month, principally on LNG. Sedans are equipped with 19-gallon LNG tanks, which typically last for 2 to 3 days of operation. Vans have 45-gallon tanks, and trucks have 43-gallon tanks, which are generally sufficient for normal operation. Drivers may switch from one fuel to the other from the driver's seat, except in the large trucks, where the driver changes fuel by setting a switch in the engine compartment.

The LNG systems used in these vehicles were assembled and installed by Atlanta Gas Light Company, using components provided by Kaiser Aerospace and Electronics of Irvine, California, and Essex Cryogenics of St. Louis, Missouri. LNG volumetric fuel consumption was not measured by Atlanta Gas Light Company, but they assume a gallon of LNG to be equal to a gallon of gasoline for state fuel tax purposes. The fuel HHV is estimated by Atlanta Gas to be 91,000 Btu/gal, which yields a fuel equivalency factor of 1.42 gal LNG/gal gasoline, for an overall estimated 42 percent energy equivalent fuel economy improvement relative to vehicle operation with gasoline. With LNG, power is perceived to be less, but drivers have not complained about power loss or hill-climbing problems. Basic spark timing is advanced slightly from the stock value, but not enough to preclude gasoline operation.

Engine maintenance is reduced with LNG, but this is counterbalanced by greater fuel system maintenance work, principally to eliminate NG leakage. Normal fuel storage time is 72 hours before venting. Overall, the LNG system operating costs reported by Atlanta Gas Light Company are about 65 percent of the equivalent gasoline costs.

B.3 CNG VEHICLE EXPERIMENTAL DATA

It is difficult to accurately assess NG as a vehicle fuel from in-use data alone. The NG user is primarily interested in cost reduction and often lacks the resources necessary to accurately measure economy,

power loss, or exhaust emissions. Nor are user records of spark timing or air-fuel ratio settings usually kept.

This section reviews the results of laboratory tests of NG-fueled engines and vehicles. These tests further illuminate the effects of NG operation by providing more detailed measurements of fuel economy, exhaust emissions, and engine power. In mos. cases, the vehicle tests compare operation over a standardized driving cycle that reduces the variability normally present during actual on-road operation. A highlight of this section is DOE's recent vehicle test program conducted at EPA's Ann Arbor Motor Vehicle Emission Laboratory.

B.3.1 Bartlesville Energy Technology Center

In 1979, Bartlesville Energy Technology Center (BETC) conducted tests on a 1978 Ford and a 1978 Oldsmobile automobile to determine the cold-start fuel economy penalties associated with short trips (Ref. B-24). The vehicles were operated on the dynamometer over a short-duration warm-up cycle originally developed by Gulf R&D. Fuel economy and emissions were measured for gasoline and CNG, both with and without exhaust gas recirculation (EGR) and spark timing adjustments.

The fuel economy warm-up trends were extrapolated to yield the fully warmed-up fuel economy estimates shown in Table B-6 for both summer and winter gasoline compositions. The baseline Ford vehicle is calibrated rich in stock condition and shows an 11 percent increase in summer fuel economy with CNG. The Oldsmobile, which has a lean stock air-fuel ratio, shows a summer fuel economy increase of 4 percent. As expected, the winter fuel economies are lower than the summer values for both CNG and gasoline. The average CNG fuel economy improvement is 1 percent for the Oldsmobile. Emissions results differed sharply between the two vehicles (Ref. B-25). The Ford showed HC, CO, and NO_x changes of +15, -81, and +74 percent on CNG, while the Oldsomobile showed +290, +56, and -22 percent. The averages of these two vehicles were +150, -12, and +26 percent.

In another program, conducted in the early 1970s, researchers at the Bartlesville Energy Research Center investigated the potential of CNG

as a low-pollution fuel for automotive applications (Ref. B-26). Data from single-cylinder Cooperative Fuel Research (CFR) engine tests showed a significant extension of the misfire limit from an excess air ratio of 1.35 for gasoline to about 1.55 for CNG. HC and NO_x emissions were lower

Table B-6. Estimated Fully Warmed-Up Fuel Economy of Two Dual-Fuel Vehicles with Gasoline and CNG (Refs. B-24 and B-25)

	ENERGY ECONOMY, BTU/MI			EQUIVALENT FUEL ECONOMY, MPG_E (1)		
	BASELINE	DUAL-FUEL		BASELINE	DUAL-FUEL	
VEHICLE	GASOLINE	GASOLINE	CNG	GASOLINE	GASOLINE	CNG
1978 FORD						
SUMMER	5350	-	4840	21.9	-	24.2
WINTER	-	6200	5380	-	18.1	20.9
1978 OLDS						
SUMMER	7280	-	6990	16.1	-	16.7
WINTER	-	7500	7570	-	15.0	14.8

(1) BASED ON LHV OF 116,981 BTU/GAL FOR SUMMER GASOLINE, 112,274 BTU/GAL FOR WINTER GASOLINE, AND 1078 BTU/SCF FOR CNG.

for CNG than for gasoline, while CO and engine power were nearly independent of fuel type. In addition, six 1968-1970 model year automobiles were tested over the cold-start, 7-mode driving cycle. At 60°F, HC emissions were 47 percent lower on CNG, CO emissions were 87 percent lower, and NO_x emissions were 22 percent lower (Ref. B-26). When operating on CNG, HC and CO emissions were relatively insensitive to changes in air-fuel ratio and spark timing. NO_x emissions and fuel consumption were strongly affected by these changes and moved in opposite directions. Power was reduced and acceleration times were increased during CNG operation.

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B.3.2 Department of Energy

B.3.2.1 Vehicle Test Program

In April, 1981, two late-model dual-fuel automobiles were tested at EPA's Motor Vehicle Emission Laboratory, Ann Arbor, Michigan, as part of this study. The vehicles were tested both in their baseline gasoline configuration and with CNG. Emissions and fuel economy were measured over the EPA city and highway driving cycles in accordance with standard Federal Test Procedures. Test vehicle specifications are listed in Table B-7. The Impala was provided by the Gas Service Energy Company, Kansas City, Missouri, and was equipped with a CNG system marketed by that company. The Diplomat was provided by Michigan Consolidated Gas Company, Detroit, Michigan, and was equipped with Dual Fuel Systems, Inc. CNG hard-

Table B-7. Test Vehicle Specifications

VEHICLE	IMPALA	DIPLOMAT
MODEL YEAR	1979	1980
INERTIA WEIGHT, LB	4000	4000
DYNO. POWER SETTING, HP	13.3	11.8
ODOMETER READING, MI	20,800	13,600
CERTIFICATION TEST NUMBER	91GF65	96443
ENGINE		
DISPLACEMENT, IN^3	305	225
CONFIGURATION	V8	L6
RATED POWER, HP	145	95
DRIVELINE		
TRANSMISSION		
TYPE	AUTO	AUTO
SPEEDS	3	3
LOCKUP	NO	YES
AXLE RATIO	2.41	2.71
N/V RATIO, RPM/MPH	31.3	35.1
NOTE:		
APPLICABLE HC/CO/NO_x STANDARDS, G/MI	1.5/15/2.0	0.41/7.0/2.0

ware. The vehicles were made available without charge for the duration of the test program. Southeast Michigan Gas Company provided NG from its facility in Albion, Michigan.

Prior to arrival in Ann Arbor, the vehicles were restored to their respective stock configurations. New catalytic converters were installed and the engines were tuned. The vehicles were inspected by EPA personnel and tested to verify that fuel economy, emissions, and mechanical condition were representative of unmodified vehicles. Emissions were within the applicable standards, except for CO on the Diplomat, which slightly exceeded the 7.0 g/mi standard. Fuel economy was within 2 mpg of the respective EPA certification values.

The vehicles were then converted back to dual-fuel operation and adjusted to the conversion equipment manufacturer's specifications. Spark timing was not changed, and air-fuel ratio with CNG was adjusted for minimum emissions at idle and low load. Equipment installation and all adjustments were performed by representatives of the conversion equipment manufacturers, or by professional trained mechanics. After conversion, the cars were retested on gasoline prior to testing with CNG. Triplicate tests in each configuration were nominally planned, but daily review of the test results permitted as few as two or required as many as five. Upon conclusion of the fuel economy and emissions tests, 5 to 60 mph and 30 to 60 mph acceleration times at WOT were measured on the dynamometer for vehicle operation on gasoline and CNG.

Chemical analysis of the test gasoline was performed by EPA. NG samples were taken at each CNG fill and were analyzed by Michigan Consolidated Gas Company for composition, heating value, and specific gravity. Analysis results are listed in Table B-8. For each test, CNG fuel economy was computed using an adaptation of the standard carbon-balance technique, as described in the following subsection.

Although conversion to dual-fuel operation increases vehicle weight by up to 300 lb, the dynamometer inertia weight settings after CNG conversion were not changed. Increasing the inertia weight would have

Table B-8. Natural Gas Composition and Properties

PARAMETER	SAMPLE 1	SAMPLE 2	AVERAGE
MOLECULAR COMPOSITION, MOLAR PERCENTS			
METHANE	90.52	91.41	90.97
ETHANE	3.22	3.26	3.24
PROPANE	0.45	0.46	0.46
BUTANES	0.13	0.15	0.14
PENTANES	0.04	0.04	0.04
HEXANES	0.02	0.02	0.02
HEPTANES	0.01	0.02	0.02
OCTANES	0.01	0.01	0.01
NONANES	0.01	0.01	0.01
NITROGEN	4.24	3.89	4.07
CARBON DIOXIDE	1.23	0.62	0.93
HELIUM	0.12	0.11	0.12
ATOMIC COMPOSITION, WEIGHT PERCENTS			
FUEL CARBON			
-INCLUDING CO_2	68.75	69.86	69.31
-EXCLUDING CO_2	67.91	69.43	68.67
FUEL HYDROGEN	22.22	22.71	22.47
PROPERTIES(1)			
HHV, BTU/SCF	987	998	992
LHV, BTU/SCF	890	900	895
DENSITY, G/SCF	21.004	20.761	20.883
ENERGY EQUIVALENCY FACTOR(2), SCF/GAL	130.9	129.5	130.2

(1) CNG AND GASOLINE PROPERTIES ARE AT 60^{0}F.
(2) GASOLINE SPECIFIC GRAVITY 0.74; LHV 18,900 BTU/LB.

made it difficult to separate the effects of CNG operation and vehicle weight change. Instead, weight effects were determined by computer simulation. Results from these analyses are presented in Subsection B.3.2.3.

B.3.2.2 Fuel Economy Calculation Methodology

Current EPA test procedures use the carbon balance method to determine vehicle fuel economy. This method assumes that the net increase of carbon atoms in the exhaust reflects carbon atoms from the fuel consumed, as follows:

$$mpg = \frac{\text{grams carbon per gallon fuel used}}{\text{grams carbon emitted per mile}} \qquad \text{(B-1)}$$

Total emissions of the three carbon-containing emission species HC, CO, and carbon dioxide (CO_2) are measured during the test, and from these the carbon-atom mass emissions can be calculated. Analysis of the fuel provides its carbon content. Although HC in the exhaust is composed of many species, the EPA procedure assumes that the HC carbon weight fraction is the same as that of the unburned fuel. This assumption is satisfactory, based on compositional analyses of HC emissions from gasoline- and CNG-fueled engines. In practice, the calculation is usually insensitive to this assumption. For the type of gasoline specified by EPA, fuel economy is given by:

$$mpg = \frac{2421}{0.866\ HC + 0.429\ CO + 0.273\ CO_2} \qquad \text{(B-2)}$$

This equation is not applicable to other fuels. In particular, for CNG, the carbon balance equation must be adjusted to account for differences in carbon weight fraction and for the presence of gaseous CO_2 in the fuel. For example, the CNG samples taken during this program had an average carbon weight fraction of 0.693 and a CNG specific gravity (compared with air at standard conditions) of 0.604. To prevent double counting of the fuel-derived CO_2 in the exhaust, the exhaust HC carbon fraction must reflect only non-CO_2 carbon species, resulting in an adjusted exhaust HC carbon weight fraction of 0.687. Based on these factors, the CNG fuel economy, expressed in terms of miles per hundred cubic feet (ccf), is:

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$$\frac{mi}{ccf} = \frac{1447}{0.687\ HC + 0.429\ CO + 0.273\ CO_2} \qquad (B\text{-}3)$$

The gasoline equivalent fuel economy for CNG may be calculated using the energy equivalency factor. For the average gas used in these tests, the factor is 130 scf/gal. Therefore:

$$mpg_e = \frac{1885}{0.687\ HC + 0.429\ CO + 0.273\ CO_2} \qquad (B\text{-}4)$$

Because of large regional variations in CNG composition, this equation is not universally applicable. Typically, the LHV for CNG ranges from 840 to 1020 Btu/scf, causing the numerator of Equation B-4 to vary from 1600 to 2000. In addition, fuel specific gravity and carbon fraction vary with CNG composition, which further affects both the numerator and denominator of the equation.

B.3.2.3 Experimental Results

Fuel economy, emissions, and acceleration results from the vehicle tests are shown in Figures B-6 and B-7, and average values are listed in Table B-9. Statistical tests were applied to determine the significance of variations between and within each test configuration. As indicated in the figures, test-to-test variations are small. Urban and highway fuel economies with CNG were essentially identical to those of the baseline gasoline vehicles. Also, there was little difference between the stock and dual-fuel gasoline results, except that CO and NO_x increased by about 15 to 30 percent. With CNG, HC increased by 100 to 200 percent over the baseline, but the increase is due to higher methane emissions. Reactive (non-methane) HC is actually lower by about 35 to 55 percent. Current automotive exhaust catalysts are relatively ineffective in eliminating non-reactive methane. However, both vehicles easily pass the proposed 1983 non-methane HC standard of 0.39 g/mi. CO was virtually eliminated, particularly in the Diplomat, and NO_x was reduced relative to the post-conversion gasoline levels. Compared with pre-conversion levels, the Impala showed significantly lower NO_x emissions with CNG, while the

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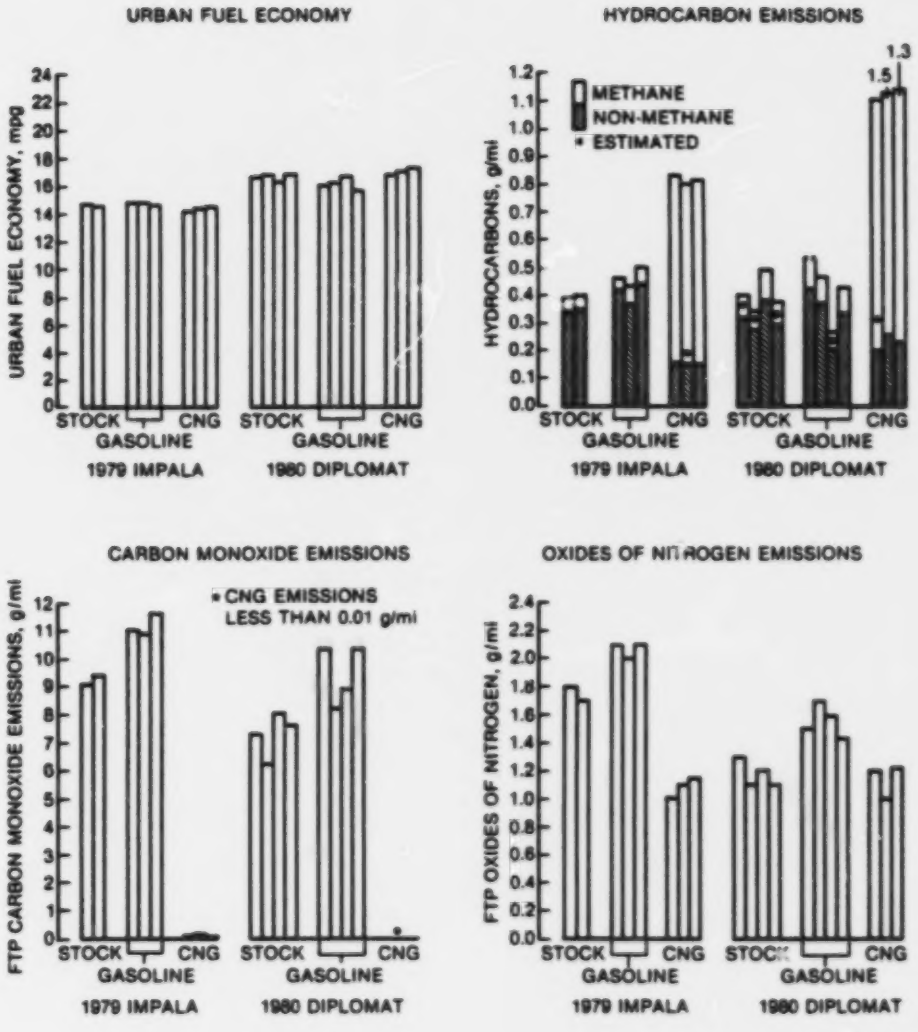

Figure B-6. Urban Cycle Fuel Economy and Emissions for 1979 Impala and 1980 Diplomat with Gasoline and CNG

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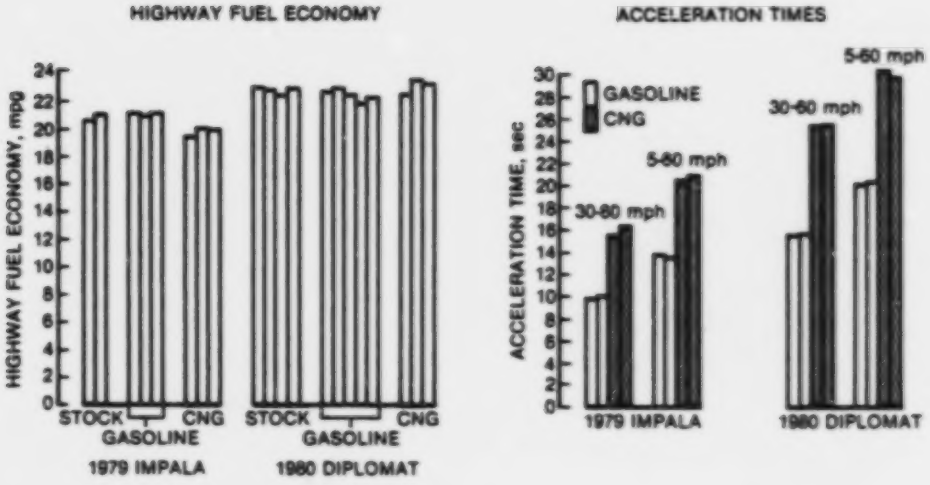

Figure B-7. Highway Cycle Fuel Economy and Acceleration for 1979 Impala and 1980 Diplomat with Gasoline and CNG

Table B-9. Summary of DOE/EPA Test Results

CONFIGURATION	EMISSIONS[1], g/mi HC	NMHC	METHANE	CO	NO_x	FUEL ECONOMY[1], MPG CITY	HWY	ACCEL. TIME, sec 5-60 mph	30-60 mph
1979 IMPALA									
BASELINE	0.40	0.34	0.05	9.2	1.8	14.6	20.8	-	-
GASOLINE	0.46	0.40	0.06	11.2[2]	2.1[2,4]	14.7	21.0	13.6	9.8
NATURAL GAS	0.82[2,3]	0.15[2,3]	0.67[2,3]	0.06[2,3]	1.1[2,3]	14.4	19.8[3]	20.4[3]	15.8[3]
1980 DIPLOMAT									
BASELINE	0.40	0.38	0.11	7.3[4]	1.2	16.6	22.7	-	-
GASOLINE	0.42[4]	0.37	0.10	9.4[2,4]	1.6[2]	16.0	22.4	20.1	16.0
NATURAL GAS	1.31[2,3,4]	0.24[3]	1.18[3]	0.003[2,3]	1.2[3]	17.0	23.1[3]	30.0[3]	25.2[3]

(1) AVERAGE OF VALID TESTS.
(2) DIFFERENCE FROM BASELINE IS SIGNIFICANT AT 95 PERCENT CONFIDENCE LEVEL, AND IS MORE THAN 6 PERCENT OF BASELINE.
(3) DIFFERENCE FROM GASOLINE IS SIGNIFICANT AT 95 PERCENT CONFIDENCE LEVEL, AND IS MORE THAN 6 PERCENT OF GASOLINE.
(4) EXCEEDS APPLICABLE EMISSION STANDARD.

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Diplomat returned to baseline. Averaging the test results of both vehicles, the HC/CO/NO_x emissions were +150/-99/-20 percent of baseline, while fuel economy was, at most, increased by 1 percent over baseline. Acceleration times were increased by 50 to 60 percent on CNG.

The average non-methane fractions of the HC emissions listed in Table B-10 show values between 13 and 18 percent for CNG, and 56 tc 87 percent for gasoline. These results are in good agreement with the fractions determined by the State of California Air Resources Board (CARB) and by Dual Fuel Systems, Inc.

Table B-10. Average Non-Methane Fraction of HC Emissions

VEHICLE CONFIGURATION	NON-METHANE HC FRACTION			
	IMPALA		DIPLOMAT	
	CITY	HIGHWAY	CITY	HIGHWAY
BASELINE	0.87	0.57	0.78	0.56
GASOLINE	0.87	0.58	0.79	0.59
NATURAL GAS	0.18	0.16	0.17	0.13

Table B-11 compares the percentage differences between Bag One and Bag Three of the Federal Test Procedure. These portions of the test cycle are identical, except that Bag One is a cold start, while Bag Three is a hot start. As expected, the hot start generally produces lower emissions and higher fuel economy than the cold start. This is in good agreement with data published by BETC (Ref. B-25).

B.3.2.4 Computer Simulations

In most conventional vehicles, the manufacturer can trade performance for fuel economy at essentially zero cost. Use of a numerically lower axle ratio or a smaller engine are two examples. To a much lesser extent, driving range can be sacrificed for better fuel economy, because a smaller tank capacity results in lower vehicle weight. Equal performance

Table B-11. Comparison of Hot-Start versus Cold-Start Emissions and Fuel Economy with CNG

VEHICLE	CHANGE FROM BAG #1 TO BAG #3, PERCENT HC	CO	NO_x	MPG_E
1981 ARIES[1]	-27	- 94	-47	+14
1981 MALIBU[1]	-32	- 94	-10	+16
1981 DODGE VAN[1]	+ 5	- 90	+59	+31
1981 FORD PICKUP[1]	-28	+ 26	-16	+19
1979 IMPALA[2]	-14	-100	-26	+16
1980 DIPLOMAT[2]	-22	-100	- 4	+15
MEDIAN	-24	- 94	-13	+16

(1) PROVIDED BY DUAL FUEL SYSTEMS, INC.
(2) DOE/EPA TEST PROGRAM.

and driving range is therefore the proper basis for comparison of CNG and gasoline vehicles. To obtain this kind of comparison, computer simulations were performed for the Impala and Diplomat vehicles to estimate the effect of lower performance with CNG on fuel economy. In addition, the effects of vehicle weight increases with CNG were estimated. Although in principle the comparison should also be performed at equal emissions, exhaust after-treatment devices complicate this issue, and reliable computer simulation of emissions is, at any rate, beyond the current state of the art.

The performance of CNG-equivalent gasoline vehicles was analyzed using VEHSIM, a computer program originally developed by the Department of Transportation (DOT) (Ref. B-27). After validating model accuracy by computing city fuel economy and WOT acceleration times for the stock vehicles, the program was used to investigate the effects of power and weight changes on fuel economy and WOT acceleration.

Figure B-8 shows the computed effects of power reduction on the acceleration capabilities of the Impala and Diplomat vehicles tested in the DOE/EPA program. The computer results can be represented by a linear function of the form

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$$1/t = C\,(P - P_o) \qquad \text{(B-5)}$$

where t is the acceleration time at rated engine power P, and C and P_o are constants for each vehicle and acceleration rate. Physically, P_o represents the power level which just balances engine and drivetrain power requirements at terminal speed, so that an infinite amount of time is necessary to reach that speed. If t_1 is the acceleration time at P_1, and t_2 the time at P_2, then the power loss may be written as

$$(P_2/P_1)^{-1} = (1-k)\ t_2/t_1 + k \qquad \text{(B-6)}$$

where k is a constant. For Figure B-8, k is in the range of 0.2 to 0.3. Figure B-8 also shows the actual acceleration times of the two vehicles tested. All four acceleration results indicate a power loss of 25 to 28 percent with an average power loss of 27 percent. This is consistent with other reported CNG values for stock timing and minimum emissions (Refs. B-12 and B-18).

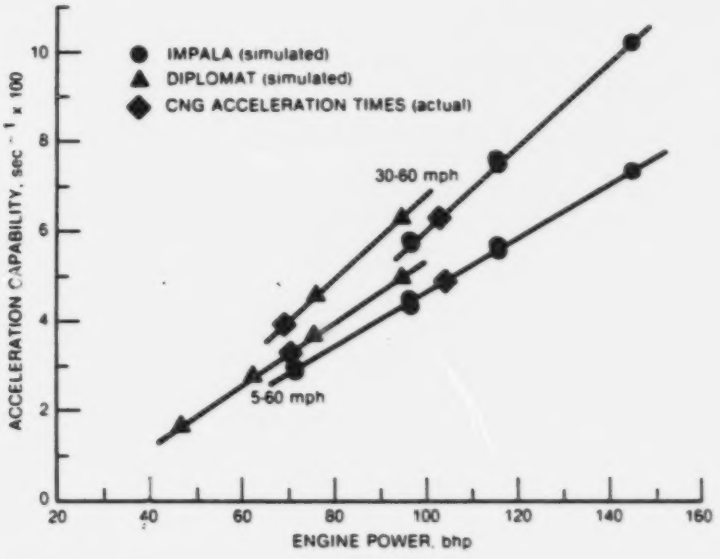

Figure B-8. Effect of Engine Rated Power on Acceleration Capability

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Figures B-9 and B-10 show the effects of weight and power changes on fuel economy. The reference condition in each case is the stock vehicle as tested. These data were used to compare simulated gasoline and NG vehicles with equal 5 to 60 mph acceleration times. Conversion of the stock vehicle to dual-fuel operation was assumed to add 250 lb. Operation on NG was simulated by a reduction in engine power of 28 percent for the Impala and 25 percent for the Diplomat, to match the measured performance reductions. CNG fuel economy was computed using the fuel economy ratios in Figures B-9 and B-10 applied to the measured CNG fuel economy. Performance was then matched by a gasoline counterpart at the original weight but with a smaller engine.

Table B-12 shows the results of this simulation. Case 2 simulates the effect of conversion equipment weight. Acceleration times increase to 14.6 sec for the Impala and 16.6 sec for the Diplomat, and fuel economy decreases by 3 percent and 1 percent, respectively. The equal-performance gasoline counterparts require only 94 percent of the original power, and show correspondingly improved fuel economy. In Case 3, engine power is reduced to simulate the effect of the CNG performance degradation. The Impala fuel economy decreases by an additional 1 percent, while the Diplomat shows a 2 percent improvement. These shifts reflect the changes obtained with the actual test vehicles, as shown in Table B-9. The CNG vehicles in Table B-12 are slightly slower than the actual vehicles, which were tested at the baseline inertia weights of 4000 lb. The equal-performance gasoline vehicles for Case 3 require about 70 percent of the original power. Fuel economy is increased by 1.4 and 2.9 mpg over baseline, to give the Diplomat an 8 percent gain and the Impala a 20 percent gain.

Case 4 simulates the effect of using a larger engine with CNG, to match baseline performance. The net fuel economy penalty for CNG use is then 23 and 14 percent for the Impala and Diplomat, respectively.

In summary, these simulations reveal that, if CNG's power loss without spark advance or engine modifications can be accepted, a 1 to

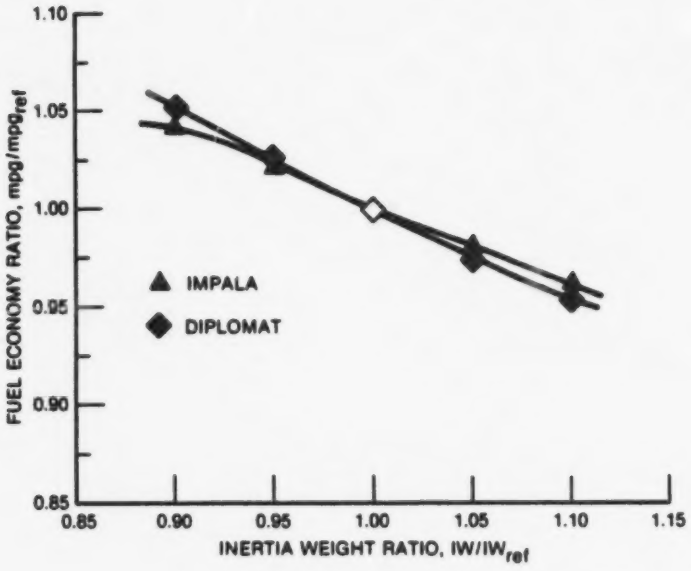

Figure B-9. Effect of Inertia Weight on City Fuel Economy

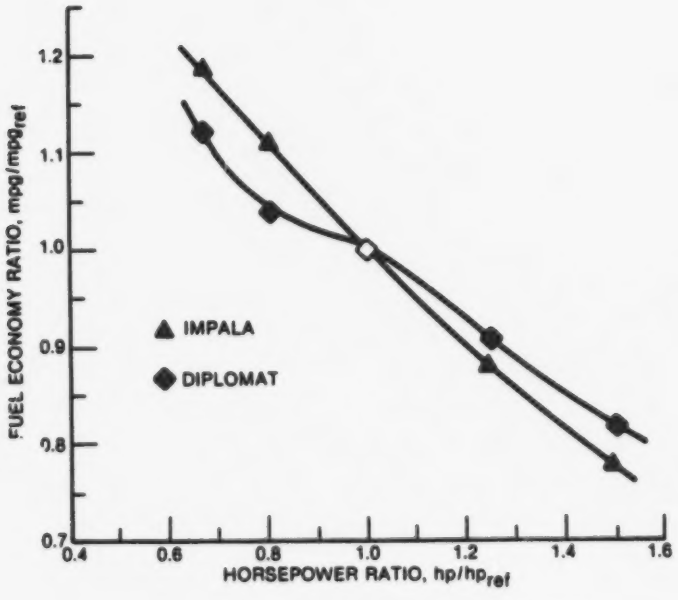

Figure B-10. Effect of Engine Rated Power on City Fuel Economy

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Table B-12. Effect of Weight and Power Changes on Performance and Fuel Economy

CASE	DESCRIPTION	RATED[1] ENGINE POWER, BHP	INERTIA WEIGHT, LB	5-60 MPH ACCEL. TIME, SEC	FUEL ECONOMY ABSOLUTE, MPG_E	FUEL ECONOMY CHANGE, PERCENT
1.	IMPALA BASELINE	145	4000	13.6	14.6	BASE
2.	ADD CNG SYSTEM (+250 LB)	145	4250	14.6	14.2	- 3
	GASOLINE EQUAL	137	4000	14.6	15.0	+ 3
3.	USE CNG FUEL	145	4250	22.4	14.0	- 4
	GASOLINE EQUAL	98	4000	22.4	17.5	+20
4.	RESTORE CNG PERFORMANCE	214	4250	13.6	11.3	-23
1.	DIPLOMAT BASELINE	95	4000	20.1	16.6	BASE
2.	ADD CNG SYSTEM (+250 LB)	95	4250	21.8	16.4	- 1
	GASOLINE EQUAL	89	4000	21.8	16.7	+ 1
3.	USE CNG FUEL	95	4250	33.1	16.8	+ 1
	GASOLINE EQUAL	67	4000	33.1	18.0	+ 8
4.	RESTORE CNG PERFORMANCE	135	4250	20.1	14.2	-14

(1) BASED ON USE OF GASOLINE.

3 percent loss in city fuel economy occurs relative to baseline gasoline operation due to increased vehicle weight. However, gasoline vehicles with the same reduced performance could provide 8 to 20 percent improvements over baseline fuel economy. Use of larger engines to restore baseline power with CNG results in projected fuel economy losses of 14 to 23 percent. The power loss issue is more than just academic. The largest fleet user of CNG systems, Southern California Gas Company, routinely purchases new vehicles intended for conversion with larger-than-standard engines and high numerical axle ratios, when available (Ref. B-28).

Advanced spark timing also can be used to partially restore power, either by a fixed static adjustment or by a device which advances

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timing only when the engine is operated on CNG. Neither approach is yet accepted by the CARB because of potentially adverse impacts on exhaust emissions. However, some manufacturers are offering such devices outside California, and CNG fleet operators employ them widely to improve vehicle performance and starting characteristics.

B.3.3 Dual Fuel Systems, Inc.

Dual Fuel Systems, Inc. (DFSI) assembles and markets CNG conversion kits for use in automotive applications. Because of DFSI's annual certification applications, fuel economy and emissions test data are available for model years 1977 through 1981 (Refs. B-29 and B-30). Table B-13 summarizes the results for post-conversion CNG and pre-conversion gasoline operation. Total HC emissions increased by about 60 to 700 percent for CNG, with a median increase of 340 percent. However, much of the HC is likely to be environmentally non-reactive methane. For one vehicle, a 1978 Fairmont, the non-methane HC fraction was measured at 13 percent. For the remaining vehicles, the methane fraction was estimated, based on correction factors established by CARB. With CNG, the reactive non-methane HC was generally lower after conversion, showing a median decrease of 41 percent. CO was reduced to insignificant levels in many cases, and NO_x levels declined significantly, with a median decrease of 46 percent. Pre-conversion and post-conversion hot-start tests with gasoline showed higher vehicle-to-vehicle variability, but CO and NO_x were generally lower after conversion.

Fuel economy data for CNG are rather limited. However, by assuming CNG properties, the fuel economy for additional tests may be estimated from the emissions data by means of the carbon-balance method. Based on an assumed CNG/gasoline equivalency factor of 126 scf/gal, the fuel economy values listed in Table B-14 were computed for the four 1981 model year vehicles included in the DFSI data sample. As indicated, the fuel economy changes with CNG range from an 11 percent improvement to an 8 percent loss. In light of the relatively low exhaust emissions with CNG,

Table B-13. Emissions Test Results for California Light-Duty Vehicles Converted by Dual Fuel Systems, Inc. (Refs. B-29 and B-30)

	EMISSIONS, G/MI							
	BASELINE GASOLINE				NATURAL GAS			
VEHICLE	HC	NMHC	CO	NO_x	HC	NMHC	CO	NO_x
'77 LTD	0.43	0.38	17.7(1)	1.3	1.12	0.22	7.8	1.1
'77 SEVILLE	0.22	0.20	2.2	1.7(1)	1.40	0.28	0.1	1.3
'77 200 SX	0.20	0.18	6.4	0.9	1.14	0.23	0.2	0.1
'77 DATSUN PICKUP	0.52	0.46	5.6	1.3	1.64	0.33	0.1	1.2
'78 FAIRMONT	0.40	0.32(2)	1.8	1.7(1)	2.08	0.27(2)	0.02	0.5
	0.28(3)	0.23(2,3)	1.4(3)	1.8(3)	-	-	-	-
'78 FAIRMONT	1.0(1)	0.82(1)	24.1(1)	1.3	1.69	0.22(2)	0.00	0.5
'79 CLUB WAGON	0.55	0.49	6.2	1.1	3.62	0.49	0.03	0.2
'80 CITATION	0.32	0.28	5.4	0.7	0.69	0.09	0.2	0.3
'80 LTD	0.51(1)	0.43(1)	7.8	0.5	1.69	0.22	0.3	0.3
'80 DODGE PICKUP	0.24	-	1.7	2.2	0.85	0.11	0.1	1.4
'81 MALIBU	0.29	-	4.6	0.6	2.31	0.30	0.1	0.4
'81 ARIES	0.36	-	4.5	0.5	0.55	0.07	0.2	0.7
'81 DODGE VAN	0.25	-	7.7	2.5(1)	1.95	0.25	1.4	1.0
'81 FORD PICKUP	0.34	-	5.0	1.0	2.82	0.37	2.1	0.4

(1) EXCEEDS APPLICABLE EMISSION STANDARD.
(2) MEASURED HC FRACTION, ALL OTHER NON-METHANE HC (NMHC) FRACTIONS ARE BASED UPON METHANE CONTENTS ASSUMED BY CARB.
(3) POST-CONVERSION TEST RESULTS.

Table B-14. Estimated City Fuel Economy of Four 1981 Model Vehicles with Gasoline and CNG (Ref. B-30)

	FUEL ECONOMY, MPG_E		
VEHICLE	GASOLINE BASELINE	CNG CONVERSION	IMPROVEMENT WITH CNG, PERCENT
1981 MALIBU	15.2	15.7	3
1981 ARIES	18.6	20.7	11
1981 DODGE VAN	10.8	9.9	-8
1981 FORD P/U	14.1	13.5	-4
AVERAGE	14.7	14.9	1

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spark advance in the CNG mode would probably be permissible in most cases and would result in higher fuel economy.

B.3.4 General Motors Corporation

The effects of emission control system modifications on power output and emissions of a CNG-fuel 1967 Chevrolet automobile were investigated by Benson (Ref. B-15). As shown in Table B-15, the use of CNG resulted in a 10 percent loss in engine power. This loss was attributed to leaner air-fuel ratio operation with CNG. Use of a catalytic converter, EGR, spark retard, and mixture enrichment at high loads resulted in significant emission reductions, particularly with CNG. However, the power loss with CNG increased to 20 percent.

In engine dynamometer tests of a 1970 model year 350 CID spark ignition engine, thermal efficiency was found to be nearly the same for gasoline and CNG at optimum air-fuel ratio and spark advance settings (Ref. B-31). However, because of the lower volumetric engine efficiency on CNG, engine power corresponding to the leanest-for-best-torque (LBT) air-fuel ratio and the minimum-for-best-torque (MBT) spark advance settings was reduced by about 15 percent at wide open throttle. The engine operated at leaner air-fuel ratios on CNG and required no cold-start enrichment. As a result, CNG provided significant reductions in HC and CO emissions relative to operation on gasoline.

Table B-15. Exhaust Emissions and Relative Power of a 1967 Chevrolet with Gasoline and CNG (Ref. B-16)

	GASOLINE				CNG			
CONFIGURATION	HC, G/MI	CO, G/MI	NO_x, G/MI	REL. POWER	HC, G/MI	CO, G/MI	NO_x G/MI	REL. POWER
BASELINE	-	-	-	1.0	-	-	-	0.9
EGR, CATALYST, SPARK RETARD, MIXTURE ENRICHMENT	0.26	3.0	0.5	1.0	0.26	1.84	0.25	0.8

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B.4 LNG VEHICLE EXPERIMENTAL DATA

LNG experimental vehicle data acquired from three sources are presented in the following subsections. The sources are (1) Beech Aircraft Corporation, (2) San Diego Gas and Electric Company, and (3) Shell Research, Ltd.

B.4.1 Beech Aircraft Corporation

Beech Aircraft Corporation has developed an automotive LNG conversion kit, and has installed it in a 1980 Pontiac Phoenix with a 2.8 liter engine and manual transmission (Refs. B-32 and B-33). The conversion included no major engine modifications.

With 18 gallons of LNG, a maximum driving range of 386 miles was measured by Beech over a route consisting of highway and suburban driving (Ref. B-32). This corresponds to a fuel economy of 21.4 miles per gallon of LNG. Based on a Beech-supplied LHV of 77,000 Btu/gal, the fuel equivalency factor is 1.51 gal LNG/gal gasoline. Thus, the converted Phoenix achieved 32.3 mpg_e over the route used by Beech. Unfortunately, preconversion fuel economy was not measured for this test route. The EPA composite fuel economy for this vehicle is 24 mpg, but close comparison of these results is not warranted because of driving cycle and vehicle differences. It should be noted that engine power was estimated by Beech to be 8 to 10 percent higher with LNG than with gasoline.

In 1979, the Beech vehicle was tested by Mercedes Benz of North America, Inc. at its High-Altitude Vehicle Emissions Laboratory in Denver, using the CVS-75 test procedure with a hot start (Ref. B-33). Table B-16 summarizes the test results. The fuel economies are based on the carbon-balance method for a gasoline fuel, with a correction factor to account for the lower fuel density of LNG (Ref. 3-33). Apparently, no correction was made to account for LNG's lower carbon weight fraction, and the fuel economies shown in Table B-16 may be 12 percent high.

Vehicles tested at high altitude generally have higher HC and CO emissions but lower NO_x and lower fuel economy. This is attributed to

Table B-16. CVS-75 High-Altitude Hot-Start Test Results with an LNG-Fueled 1980 Phoenix Automobile (Ref. B-33)

SPARK TIMING, $^{o}_{BTDC}$	AIR-FUEL RATIO	EMISSIONS, G/MI HC	CO	NO_x	FUEL ECONOMY, MPG_E (1)	REMARKS
12	RICH	0.248	9.0	2.70	16.2	OPTIMUM PERFORMANCE
9	LEAN	0.128	1.57	1.99	16.8	MINIMUM HC AND CO
20	LEAN	0.457	7.85	3.53	19.0	REMOVED CATALYST, MINIMUM HC AND CO

(1) GASOLINE-DERIVED CARBON-BALANCE FUEL ECONOMY, WITH CORRECTION FOR LNG DENSITY BUT NOT FOR LNG CARBON MASS FRACTION.

mixture enrichment caused by the lower density of air at high altitudes. Based on EPA's methodology for deriving the 1982 high-altitude standards, corresponding 1980 values of 0.57 g/mi HC, 11.4 g/mi CO, and 2.0 g/mi NO_x, were calculated to permit comparison to the high-altitude test results. The Beech vehicle passes the HC and CO standards in all modes, but exceeds the NO_x standard.

Based on the Denver tests, HC and CO emissions from the Beech vehicle are similar to those of similar gasoline vehicles, while NO_x emissions are increased. Fuel economy is decreased by an unknown amount. Based on the design of the Beech system and comments provided by LNG users, some decrease in engine power is probable if emission regulations are met simultaneously.

B.4.2 San Diego Gas and Electric Company

In the early 1970s, San Diego Gas and Electric Company operated five vehicles on LNG (Ref. B-10). Reported HC, CO, and NO_x emissions over the 7-mode driving cycle are 0.45, 1.0, and 1.1 g/mi, respectively, including the then-current assumed reactivity factor of 0.5 for HC. Vehicle emissions on gasoline are not available, and vehicle age and model are not identified by the data source.

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B.4.3 Shell Research, Ltd.

Shell Research, Ltd., of Great Britain converted an SI engine to LNG operation and tested its performance on an engine dynamometer, and in a vehicle over the 7-mode driving cycle (Ref. B-22). Engine compression ratio was increased from 8.2 to 11.2, and a CDI system was added. An intake air to LNG heat exchanger vaporized the fuel. The excess air ratio varied between 16 and 20 percent. Spark timing was set 20 to 25 deg before the corresponding gasoline setting, which is considerably more than the advance used by most CNG system operators.

Vehicle fuel economy results are shown in Table B-17. The maximum-economy setting resulted in a 6 and 19 percent reduction in fuel consumption over an unidentified urban/suburban driving cycle and a taxi cycle, respectively, for an average decrease of 13 percent over the two cycles. These results are consistent with the dual-fuel vehicles discussed earlier, which registered large gains over delivery-type cycles. Over the 7-mode driving cycle, NO_x increased by 47 percent and HC and CO decreased by 65 and 80 percent for the maximum economy mode. Retuning for minimum emissions by using a 30:1 air-fuel ratio combined with spark advance and a CDI system to restore drivability resulted in lower NO_x, accompanied by an increase in fuel consumption. Despite the compression ratio increase and timing advance, post-conversion engine power was 5 to 32 percent lower than the stock engine, with an average power loss of 24 percent.

B.5 DIESEL ENGINE OPERATION WITH NG

To date, the use of NG in diesel engines has been restricted to stationary or marine engines rather than highway vehicles. Since NG has a high resistance to autoignition, it is unsuitable for use in diesel engines unless chemical or thermal ignition aids are used. Chemical ignition aids may be diesel fuel, often used as a "pilot" to ignite the NG. Thermal aids may be heated combustion surfaces or modified spark plugs.

In principle, NG may be introduced into the engine either by induction into the intake manifold or directly into the cylinder. In the

Table B-17. Vehicle Energy Consumption and Emissions with Gasoline and LNG (Ref. B-22)

MODE	ENERGY CONSUMPTION, BTU/MI: TAXI CYCLE	ENERGY CONSUMPTION, BTU/MI: URBAN/SUBURBAN CYCLE	EMISSIONS, G/MI(1): HC	EMISSIONS, G/MI(1): CO	EMISSIONS, G/MI(1): NO_x
LNG-MAX ECONOMY	6220	4720	2.3	3.7	8.1
LNG-MIN EMISSIONS	6930	5590	2.5	1.9	0.51
GASOLINE-STOCK	7650	5020	6.6	18.7	5.5

(1) 1970 U.S. SEVEN-MODE CYCLE. APPLICABLE CALIFORNIA STANDARDS WERE: 2.2 G/MI HC AND 23 G/MI CO (NO NO_x REQUIREMENT).

case of induction, or fumigation, the diesel pilot accounts only for 25 to 35 percent of total engine fuel at full power. With direct cylinder injection, the pilot accounts only for 5 to 10 percent of total fuel at full power (Refs. B-34 through B-36). As power decreases, the pilot charge makes up an increasing percentage of total fuel until, at idle, the engine is operating mostly or exclusively on diesel fuel. This variable pilot to gaseous fuel ratio requires a sophisticated control system for optimum fuel utilization. For example, Wellington Gas Company of New Zealand uses an electronic governor that permits a stationary diesel engine to operate on 85 percent CNG, with a 10 percent increase in torque and no increase in fuel consumption (Ref. B-34). Since stationary and marine engines typically operate at constant speed and load for long periods of time, the need for complex automatic controls is not strong.

At constant power, single-cylinder CFR engine tests with fumigated diesel fuel have shown a reduction in exhaust opacity from 60 percent to 12 percent (Ref. B-37). Alternatively, at a constant 60 percent opacity, engine power was increased significantly at higher engine speeds, as shown in Figure B-11, while specific fuel consumption was reduced. Other tests with optimized engine timing show fuel consumption improvements of up to 10 percent.

A number of Italian investigators have studied CNG fumigation in direct-injection diesel engines (Ref. B-35). A maximum-power CNG fraction of 90 percent produced injector nozzle overheating and carbon buildup in one six-cylinder Fiat engine. The optimum full-power CNG fraction for the Fiat engine was 75 percent. After 9000 hours of operation at the optimum pilot fuel to CNG ratio, mechanical wear was similar to a stock engine.

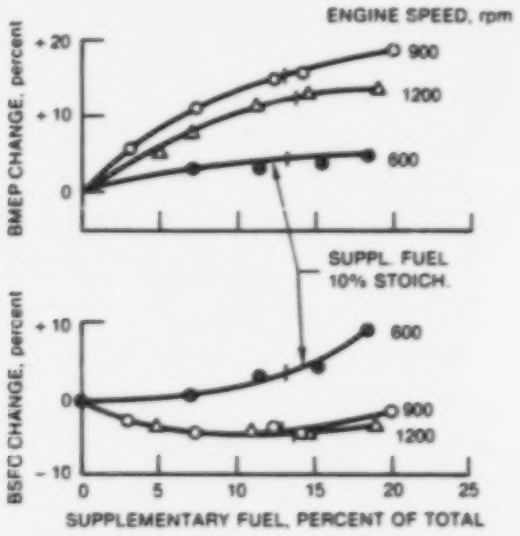

Figure B-11. Effect of NG Fumigation on Constant-Smoke Power and Fuel Consumption for a CFR Diesel Engine (Ref. B-37).

Figure B-12 compares engine power output for normal diesel operation and for CNG fumigation with pilot injection. At peak thermal efficiency, which occurs at about 1500 rpm, fumigation increases engine power by 6 percent. This increase is in good agreement with the CFR data of Reference B-37.

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Methane fumigation experiments conducted by Canadian researchers on a 1.4 liter single-cylinder, direct-injection diesel engine indicate significant losses in combustion efficiency at charge intake temperatures below 32°F (Ref. B-38). In these tests, the addition of methane increased ignition delay, particularly for lean mixtures, and the low inlet temperatures exacerbated this effect. As a result, combustion temperatures were reduced and power output suffered at low loads (Ref. B-39). Advancing injection timing to counteract the delay was of limited success (Ref. B-38). As expected, methane addition resulted in increased levels of exhaust methane. At low loads, 20 to 80 percent of the fuel methane left the engine unreacted. CO levels increased by as much as 600 percent with fumigation, while part load NO_x was lower than with standard diesel operation. At high loads, NO_x levels were equal to or higher than those of normal diesel fuel operation. Exhaust smoke intensity was reduced over the entire load regime, because methane burns nearly soot-free.

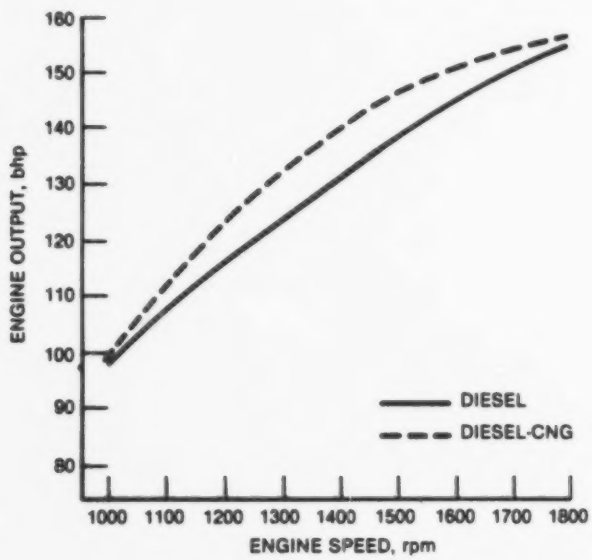

Figure B-12. Effect of Methane Fumigation on Power Output of a Six-Cylinder Fiat Diesel Engine (Ref. B-35)

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The Southwest Research Institute (SwRI), under contract to DOT, converted a Detroit Diesel 6V-71N engine to LNG operation, and conducted engine dynamometer tests over the 13-mode cycle (Ref. B-40). High-pressure gas injection into the cylinders and a spark-ignition system were used. As indicated in Table B-18, CO and total HC increased considerably with LNG. However, much of the HC is believed to be methane. HC increased by 1300 percent and CO by 300 percent, while NO_x decreased by 27 percent.

Table B-18. Thirteen-Mode Cycle Exhaust Emissions from an LNG-Fueled Diesel Engine (Ref. B-40)

	EMISSIONS, G/BHP-HR	
POLLUTANT	PRE-CONVERSION	LNG
HC	0.5	6.9
CO	7.7	31.9
NO_x	16.9	12.4

Cylinder-to-cylinder mixture variations were thought to be contributors to the high HC and CO emissions. However, smoke levels were below 1 percent, while 4 percent was required for visible smoke. Indicated specific energy consumption increased by 45 percent from about 5.5 Btu/hp-hr on diesel fuel to 8 Btu/hp-hr on LNG, and maximum power declined by 10 percent. Subjective odor levels were lower, as was engine noise. No unusual wear or mechanical problems developed during 50 hours of testing.

B.6 METHANOL VEHICLE EXPERIMENTAL DATA

A number of exploratory research programs are presently under way to identify the basic characteristics of methanol-fueled vehicles and engines, and to evaluate methods of overcoming methanol's known shortcomings. The improvement in energy economy with methanol, of course,

depends heavily on the degree of engine calibration and hardware optimization for the new fuel, and available data do not allow a conclusive assessment of methanol's potential at this time.

Since methanol does not represent the main thrust of this report, an exhaustive search for fleet data was not performed. Instead, readily available information on representative activity was reviewed, as discussed in the following subsections, which summarize the status of methanol test and development programs in progress at or completed by (1) the Bartlesville Energy Technology Center (BETC), (2) the University of Missouri/Oldsmobile Division of General Motors Corporation, (3) the University of Santa Clara, (4) the State of California, (5) Volkswagenwerk A.G., (6) the German Ministry for Research and Technology, and (7) the Bank of America.

B.6.1 Bartlesville Energy Technology Center

Comparative tests of methanol versus gasoline were performed at the BETC on a 4500 lb inertia weight 1976 Dodge, equipped with a V-8 engine and an oxidation exhaust catalyst (Ref. B-41). Spark timing was not changed from the gasoline setting, but the air injection and EGR systems were disconnected for most of the tests. Fuel economy and emissions were measured for compression ratios of 8.5 and 13. At a fuel-air equivalence ratio of 0.8, energy consumption at the lower compression ratio was approximately 8 percent lower with methanol. Emissions of HC, CO, and NO_x decreased by 20, 33, and 70 percent, respectively, but aldehydes increased by 575 percent. Fuel economy with methanol did not change significantly when the compression ratio was increased to 13, and EGR also had little effect.

B.6.2 University of Missouri/Oldsmobile Division

Torch ignition has been studied by the University of Missouri and the Oldsmobile Division of General Motors as one way to improve cold starting and driveability characteristics with methanol (Ref. B-42). A 1.5 liter Honda CVCC stratified charge engine was modified so that the main chamber was fueled by methanol, while the prechamber used gasoline.

Tests in a 1975 Honda Civic demonstrated unassisted cold starting with methanol at temperatures below 30°F. Driveability with a warm engine was good, but cold-start driveability, based on "total weighted demerits," was rated about three times lower than that of the gasoline vehicle even after installation of an intake air preheater. No attempt was made to recalibrate the engine to take advantage of the methanol fuel, and the spark timing and air-fuel ratio remained about the same as with gasoline. Energy economy with methanol was essentially the same as with gasoline, but increased by about 6 percent with the addition of the intake air preheater. NO_x was reduced by 70 percent, while HC and CO increased somewhat.

B.6.3 University of Santa Clara

The effect of a three-way catalyst on fuel economy and emissions of five 1978 Ford Pinto vehicles, retrofitted for neat methanol, was investigated by the University of Santa Clara (Ref. B-43). The vehicles were equipped with 2.3 liter four-cylinder engines, and used closed-loop feedback control under most operating conditions to maintain a near-stoichiometric mixture. Engine modifications consisted of enlargement of the carburetor jets, upgraded fuel filtration, and addition of an electric heater to improve cold-start characteristics. Reliable cold starts were achieved for temperatures as low as 25°F. Acceleration stumble from idle, which was experienced initially, was eliminated by enrichment of the off-idle fuel-air mixture, and idle quality was improved by fitting a shorter duration cam shaft.

Measured average emissions and energy economy are shown in Table B-19, and compared with values from the unmodified vehicles operated with indolene. City energy economy is about 2 percent lower with methanol, probably because of increased fuel maldistribution with methanol and because of the low-speed mixture enrichment used in these tests. Highway energy economy, in contrast, is about 4 percent higher for methanol. As expected, aldehyde emissions increased and NO_x emissions decreased with methanol.

Table B-19. Average Emissions and Energy Economy of Five Ford Pintos with Methanol and Indolene (Ref. B-43)

PARAMETER	METHANOL	INDOLENE
EMISSIONS, G/MI		
HC	0.16	0.30
CO	2.61	2.51
NO_x	0.68	0.98
ALDEHYDES	0.032	0.011
ENERGY ECONOMY, MI/MMBTU		
CITY	174	178
HIGHWAY	213	205
NUMBER OF TESTS	38	4

Turbocharging can improve cylinder-to-cylinder fuel distribution, particularly if the compressor is downstream of the carburetor. In the latter case the compressor atomizes the fuel and aids fuel-air mixing, providing a relatively homogeneous mixture to the cylinders. A turbocharged engine is therefore more amenable to the use of methanol than a naturally aspirated engine. To confirm this expectation, engine dynamometer tests were performed at the University of Santa Clara, using a turbocharged version of the 2.3 liter Pinto engine and operating it on both indolene and methanol (Ref. B-44). For operation on methanol, the fuel jets were enlarged, engine coolant flow rates through the intake manifold and compressor inlet were increased, and the EGR valve was disconnected. Based on the measured steady-state engine maps, hot-start raw (pre-catalyst) emissions and fuel economy were calculated using computer simulations, as summarized in Table B-20. With unaltered spark timing, simulated city and highway energy economy values are, respectively, 10 and 5 percent higher with methanol than with indolene. A 5 degree spark advance increases the gains to 14 and 11 percent, respectively, at the expense of an increase in total HC and unburned fuel (UBF). This compares with changes of -2 and +4 percent, respectively, for the naturally

Table B-20. Simulated Raw Emissions and Energy Economy of a 2.3 Liter Turbocharged Ford Pinto with Methanol and Indolene (Ref. B-44)

PARAMETER	METHANOL		INDOLENE
	BASE SPARK TIMING	5^0 SPARK ADVANCE	
RAW EMISSIONS, G/MI			
HC	1.71	3.28	1.75
CO	38.1	37.4	26.4
NO_x	NA	1.15	3.94
UBF	0.85	1.64	1.75
AVERAGE EQUIVALENCE RATIO	1.10	1.10	1.05
ENERGY ECONOMY, MI/MMBTU			
CITY	172	179	157
HIGHWAY	190	201	181

aspirated version of this engine. Relative to gasoline, the use of methanol results in a substantial increase in CO, while NO_x remains essentially constant. The increase in CO with methanol is attributed to a slightly richer cycle-average equivalence ratio.

B.6.4 State of California

In July 1981, the State of California Energy Commission and the Los Angeles County Mechanical Department initiated a joint 40-car fleet test program of methanol-fueled Ford Escort and Volkswagen Rabbit vehicles (Refs. B-45 and B-46). The Escorts use 1.6 liter engines, converted to an 11.4 compression ratio, with recalibrated carburetors and modified ignition timing. For increased volatility and, hence, cold-start capability, 5.5 percent iso-pentane is added to the methanol. Corrosion-resistant materials were adopted on fuel system parts exposed to methanol. The Rabbits are equipped with 1.6 liter engines, with the compression ratio increased to 12.5. The fuel injection system and the ignition timing were both modified for methanol use, and optimized for fuel economy while satisfying California emission requirements.

Preliminary fuel economy and emission test results for the vehicles are shown in Table B-21 (Ref. B-46). The data for the gasoline Rabbit are 1981 EPA certification values, and reflect a slightly larger displacement engine with a different emission calibration. Taking engine displacement into account, equivalent fuel economy on a Btu basis is roughly the same for the gasoline and methanol vehicles, with NO_x much lower for the Escort.

Table B-21. Fuel Economy and Emissions of Escort and Rabbit Vehicles with Methanol and Gasoline (Refs. B-45 and B-46)

	ESCORT		RABBIT	
PARAMETER	1.6L. METHANOL 11.4 CR(1)	1.6L. GASOLINE 8.8 CR(1)	1.6L. METHANOL 12.5 CR(1)	1.7L. GASOLINE 8.2 CR(1)
EQUIVALENT FUEL ECONOMY, MPG_E				
CITY	24.1	24.9	28.2	26
HIGHWAY	37.2	35.2	36.9	33
COMPOSITE	28.6	28.7	31.5	29
EMISSIONS, G/MI				
HC	0.18	0.36	0.14	0.11
CO	3.77	5.95	0.8	1.37
NO_x	0.25	0.93	0.32	0.17

(1) CR = COMPRESSION RATIO.

The effect of NO_x emission requirements on fuel economy was investigated for one of the Escorts, with results shown in Table B-22 (Ref. B-46). When recalibrated to emit 0.7 g/mi NO_x, the methanol vehicle shows an equivalent city fuel economy advantage of 12 percent over gasoline, and the advantage rises to over 29 percent at the 1.3 g/mi NO_x level. The corresponding highway improvements are 22 and 45 percent, respectively.

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Table B-22. Fuel Economy of Ford Escort with Gasoline and Methanol at Various NO_x Levels (Ref. B-46)

	EQUIVALENT FUEL ECONOMY, MPG_E			
	GASOLINE @	METHANOL @		
DRIVING CYCLE	0.9 NO_x	0.25 NO_x	0.70 NO_x	1.3 NO_x
CITY	24.9	24.1	28.0	32.2
HIGHWAY	35.2	37.2	43.1	51.0
COMBINED	28.7	28.6	33.3	38.6

B.6.5 Volkswagenwerk A.G.

Volkswagen has converted several 1.6 liter Rabbits to methanol operation (Refs. B-47 and B-48). The modifications included the use of a 12.5 compression ratio, revised carburetor setting and ignition timing, and replacement of some fuel system parts. Fuel preheat, auxiliary fuel atomization, and separate starting fuels were all tested as cold-start aids, but finally the use of a fuel additive, iso-pentane, was settled on. With this additive, reliable cold starts down to -13°F were achieved. Emissions over the European ECE driving cycle showed 78, 60, and 55 percent reductions in HC, CO, and NO_x, respectively, for methanol compared with gasoline (Ref. B-48). No fuel economy results were reported for this cycle. However, a road load comparison for a similar engine indicated an equivalent fuel economy advantage of 15 to 20 percent over much of the load range.

B.6.6 German Ministry for Research and Technology

Partially because of the positive results from the first German methanol program, including the development of the Volkswagen methanol vehicles, the German Ministry for Research and Technology instituted a four-year research and demonstration program, entitled "Alternative Energies for Road Transportation," for the period from 1979 through 1982 (Ref. B-49). As part of that program, 130 cars and 42 trucks were converted in 1980 to neat methanol for subsequent in-use customer testing and evalua-

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tion. All German automobile manufacturers and several oil companies are involved in the test program, with final evaluation to take place late in 1982.

B.6.7 Bank of America

The Bank of America is conducting methanol fleet tests in California, using both neat methanol and blends with gasoline (Ref. B-50). The program is in its early stages, and no fuel economy or emissions results were given in Reference B-50.

B.7 DIESEL ENGINE OPERATION WITH METHANOL

Although the extremely low cetane number of methanol makes it unsuitable for unmodified conventional diesel engines, engine modifications or use of fuel additives could alter this conclusion. This subsection summarizes some of the recent investigations aimed at burning methanol in diesel engines.

Spark ignition of injected methanol was investigated at the University of Santa Clara, using a single-cylinder prechamber diesel engine (Ref. B-51). The tests gave mixed results for indicated thermal efficiency, showing a loss relative to diesel fuel at low load, and a small gain at full power. NO_x emissions were substantially lower, as expected, but CO and unburned fuel emissions were higher.

Tests of spark-assisted heavy-duty diesel engines using methanol were performed by MAN in Germany (Ref. B-52). The engines used direct injection, with the fuel spray directed at the wall of a spherical combustion chamber located in the piston. This allowed combustion to be controlled by the rate of evaporation and mixing from the wall, reducing the pressure rise rate in the cylinders. Vehicle tests of four- and six-cylinder engines were performed in a 2.1-ton military vehicle and in a bus, respectively. Energy consumption was 5 to 10 percent lower with methanol, with acceptable emissions, and cold starting was reportedly no problem down to -20°C.

Although the knock resistance of methanol is high, it is easily ignited by a hot surface. Engine tests at the Indian Institute of Technology have shown that this property can be exploited (Ref. B-53). In these tests a single-cylinder indirect-injection diesel engine was used, with an electrically heated surface located in the engine's spherical prechamber. Ignition delay periods were less with methanol than with diesel fuel, in contrast to the usual ignition delay versus cetane number relationship, and thermal efficiency was higher under all loads. Aldehyde emissions were higher with methanol, but were lower by factors of 4 to 6 relative to a comparable SI engine using methanol.

Brazilian investigators also have examined surface-initiated combustion of methanol in diesel engines (Ref. B-54). In these tests, commercially available glow plugs of the type used for starting conventional diesel engines were used as the ignition source. Single-cylinder and four-cylinder engine tests were performed, using direct injection in both cases. Glow plug placement was critical, but with proper placement engine startup was found to be easy. Thermal efficiency of the engine with methanol was higher than with diesel fuel at high loads, but lower at low loads.

Pilot injection of small quantities of easily ignitable fuel such as diesel fuel has also been investigated as a means of igniting injected or carbureted methanol in diesel engines (Refs. B-55 through B-57). Another approach is the use of additives to improve methanol's cetane number (Ref. B-58). Unfortunately, large quantities of additive are required unless pilot injection of treated methanol is used.

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APPENDIX C

PRODUCTION TECHNOLOGY

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This appendix presents an overview of the processing steps and technology status for the production[1] of natural gas (NG), synthetic (or substitute) natural gas (SNG), and methanol. Manufacture of the several physical forms of NG (compressed natural gas [CNG] and liquefied natural gas [LNG]) from various feedstocks is discussed, as well as the production of methanol from many of the same raw materials. The intent is to provide additional technical background to aid the reader in understanding the present NG supply system and future supplemental gas sources.

C.1 NATURAL GAS

All phases of development and utilization of gas resources are provided by private industry and fall within two major segments, supply and transportation. The former includes exploration, extraction (including drilling and production technologies), processing (purification), and conversion (compression or liquefaction). Transportation comprises transmission, storage, and distribution to the consumer. Figure C-1 illustrates the overall system.

Domestic NG, as well as imports from Canada and Mexico, are transported via pipelines. Some imported gas, principally from North Africa, has come in by tanker as LNG and is revaporized in the United States for injection into domestic gas lines. LNG is also used by numerous gas suppliers in the United States as a storage medium to meet peak or base load demands; liquefaction technology is addressed later.

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[1] In the context of this appendix, production includes all the steps from extraction of the in-place natural resource to the initiating point for retail sales.

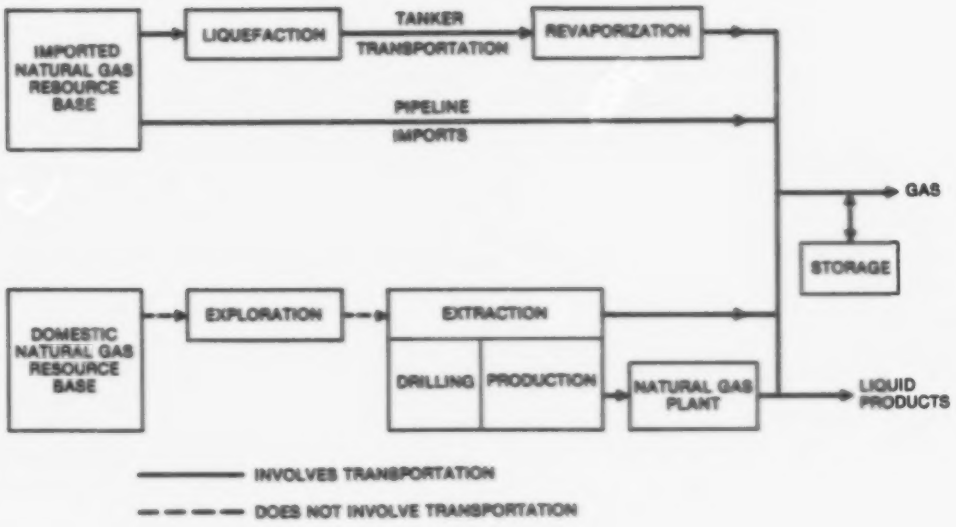

Figure C-1. Block Diagram of the Natural Gas Resource System (Ref. C-1)

C.1.1 Conventional Natural Gas

Over 95 percent of the NG produced in the United States in 1980 came from conventional onshore and offshore sources. Of this total, approximately one-quarter came from offshore wells, primarily in Louisiana, Texas, Alaska, and California. Considering only the gas moving in interstate pipelines, about 79 percent originates in Texas, Louisiana, and Oklahoma (Ref. C-1). Figure C-2 indicates the recent flow pattern of interstate gas in the lower 48 states. There were slightly over 175,000 gas wells in operation in the United States in 1980; during the year, there were almost 15,000 well completions, a new record.

Gas resource development begins with exploration to locate geological formations that are potential oil or gas reservoirs. Regional and detailed local seismic surveys are followed by core drilling of shallow holes and then exploratory drilling. Exploratory wells are usually drilled to reach a particular geological formation that is believed to

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contain gas or oil. Drill cuttings taken from the hole are used to determine which formation is being penetrated and whether hydrocarbons are present. Offshore exploratory drilling uses the same techniques as onshore, except that a mobile platform must be provided to support the drilling rig and other equipment.

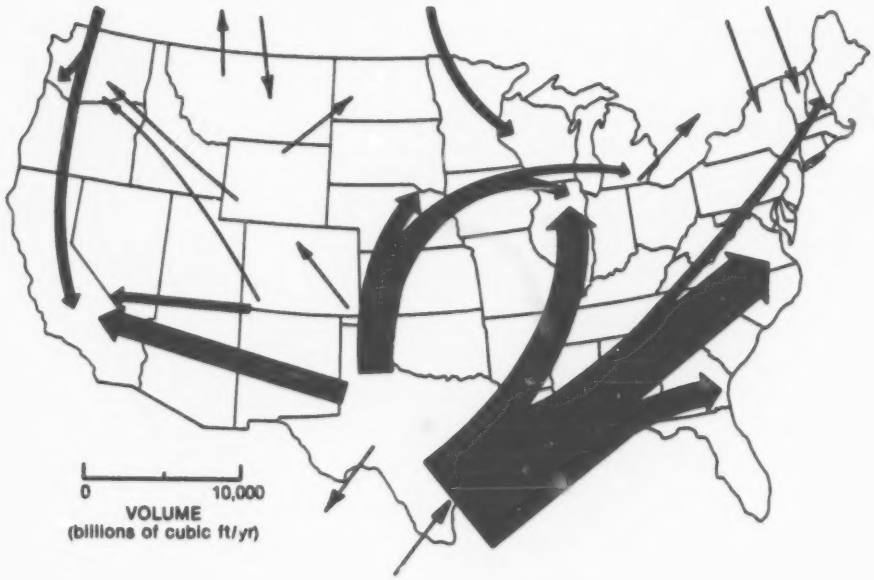

Figure C-2. Map of Natural Gas Movements in the United States (Ref. C-1)

Once gas is discovered, the well is tested to determine the possible flow rate and size of the reservoir. If the reserves calculated from these data and geological information are large enough to warrant commercial production, the reservoir is developed. Development includes drilling a number of wells to draw down the reservoir as efficiently as possible, completing these wells so that flow occurs and can be controlled, installing pipelines to gather the raw gas, and finally constructing field processing facilities. Offshore, multiple development wells are usually directionally drilled from fixed platforms. A new

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approach to offshore completions is the subsea completion at the ocean floor rather than on a platform.

The gas recovery situation in Alaska, particularly on the North Slope, differs in several ways from the lower 48 states. Commercial Alaskan production at significant levels for consumption within the state and for export as LNG to Japan began in the 1960s, from reserves in the Cook Inlet area in southern Alaska. The larger reserves on the North Slope have not yet seen commercial production due to the lack of a gas transportation system to the markets in the lower states. Gas now recovered in the course of crude oil production is, for the most part, being reinjected into the reservoirs. Among the difficulties associated with gas exploration and production in Alaska are delayed leasing schedules, the harsh arctic environment, and engineering and financial problems in constructing the Alaskan Natural Gas Transportation System. The latter is now expected to be completed in 1986 at a cost of over $20 billion (Ref. C-2).

C.1.2. Unconventional Natural Gas

Because unconventional NG tends to be more sparsely distributed in more inaccessible formations, often of low permeability, production techniques are generally quite different from conventional technology. In several cases, adequate characterization of the resource and satisfactory recovery systems have yet to be attained. On the other hand, once the NG is brought to the surface, it should pose no special problems in processing or transportation.

Table C-1 summarizes the important characteristics of the four major unconventional NG categories. The following discussion addresses each in turn without attempting to present comprehensive coverage of the subject.

C.1.2.1 Coal Seam Gas

Data on the NG content of coals in place are very sparse, being limited to about 50 coal seams out of the many hundreds that are known to

exist. The bulk of the data available pertain to safety in minable bituminous coal seams, where 200 standard cubic feet (scf) per ton of coal is near an average value; the content of subbituminous coal and lignites is less than half this value. During the past few years, data have been obtained specifically for proposed gas recovery projects, but the total amount of information is still inadequate.

Table C-1. Unconventional Gas Sources and Recovery Technology

TYPE	LOCATION	RECOVERY TECHNOLOGY	STATUS
TIGHT GAS RESERVOIRS	ROCKY MOUNTAINS, PARTICULARLY WYOMING, COLORADO, UTAH	EXPLOSIVE OR HYDRAULIC FRACTURING	0.8 TCF RECOVERED IN 1979
DEVONIAN SHALE	APPALACHIAN BASIN	EXPLOSIVE STIMULATION OR HYDRAULIC FRACTURING	0.1 TCF RECOVERED IN 1979
COAL SEAMS	KENTUCKY, PENNSYLVANIA, W. VIRGINIA, VIRGINIA, ALABAMA	(1) STIMULATED WELLS (2) HORIZONTAL HOLES FROM VERTICAL SHAFT OR MINE TUNNEL (3) SLANT HOLES FROM SURFACE	SOME LOCAL UTILIZATION AT COAL-BED SITES
GEOPRESSURED BRINES	METHANE DISSOLVED IN DEEP HOT BRINE UNDER GULF COAST	BRINE WELLS	RESEARCH STAGE. PROBLEMS OF BRINE DISPOSAL, EXCESSIVE DRILLING DEPTHS (10,000-50,000 FT), LOW WELL PRODUCTIVITY, LAND SUBSIDENCE, CORROSION.

Theoretical models to project the flow of gas through porous media, such as coal, are available, but the physical properties of coal relevant to such analyses are not available for the majority of coal seams in the country. Limited experience from NG recovery projects has indicated substantial variability in gas flow.

Pre-drainage of significant amounts of coal-bed NG can have a positive effect on the fire safety of subsequent mining operations, but there is a risk involved in some methods of gas recovery. For example, one of the four primary techniques consists of drilling vertical holes, generally 9 inches in diameter or less, from the surface to the coal seam. The amount of NG that will flow from the microporous structure of the coal is quite limited, unless the area is either naturally highly

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fractured or hydraulic fracturing is used. The latter technique uses a fracturing fluid under pressure to increase the crevice volume within the coal seam and thus improve the effective permeability. The most commonly used fluids are gelled water and nitrogen-water foams. Carefully sized sand grains are carried with the fluid to prevent the crevices from closing when th hydraulic pressure is reduced. However, there is evidence that fracturing can render some coal seams unminable, or at least increase the likelihood of roof damage and thus jeopardize the safety of the miners. Since the energy content of the gas amounts to only 1 to 2 percent of the energy in the coal, many mine owners feel that even a little risk in this regard is unwarranted (Ref. C-3).

Another recovery technique consists of drilling horizontal holes into virgin coal from active working sections of an underground mine. The coal-bed gas that is liberated is conveyed to a surface collecting site. This method is considered to be the most economical of all alternatives. However, the total potential NG recovery is not significant, inasmuch as there are only a limited number of underground mines under development at any one time.

In a third technique, vertical shafts 10 to 20 ft in diameter are sunk to the bottom of the coal seam. Working within the shaft, approximately 4-in-diameter holes are drilled radially into virgin coal. The holes intersect existing fissures and provide conductive vents for the trapped gas. Horizontal holes greater than 1000 ft have been demonstrated. The NG is piped to the surface for purification and compression. In certain situations, this method is economically comparable to a vertical well project without the safety impact of the latter.

The last method that has been tried is to drill a small-diameter vertical hole from the surface and then intentionally and progressively deflect it to penetrate the coal seam horizontally. This concept is technically difficult and more costly than any of the others. Nevertheless, two successful tests have been reported by the Bureau of Mines, and further development work may be carried out.

There are institutional, regulatory, and technical constraints on the growth of commercial NG recovery projects. The issue of gas ownership is unresolved and will have to be decided by the courts. Until then, a coal company must specifically have gas rights to legally recover and market coal-seam NG. Long horizontal gas recovery holes under land with multiple ownership introduce additional legal complexity. Environmental problems arise if large quantities of coal-bed water have to be disposed. Coal companies frequently have limited experience in the recovery, treatment, and marketing of NG. Drilling technology for long horizontal and slant holes needs improvement. Finally, more data are needed on the gas content of different coals and the parameters that control gas flow in beds (Ref. C-3).

C.1.2.2 Devonian Shale

The term Devonian shale refers to a fine-textured, laminated sedimentary rock deposited over the eastern United States some 350 million years ago, particularly in the Appalachian, Michigan, and Illinois basins. Black or brown shales are rich in organic matter, are of great thickness, extend over wide areas, and are of particular interest as a potential source of NG locked in the nonporous shale. In addition to black or brown shale, there is a less promising gray shale. In Reference C-3, the NG content of black or brown shale is given as 0.6 scf per cubic foot of shale and 0.1 scf per cubic foot of gray shale. About 9600 wells are known to be producing from Devonian shale (Ref. C-3) with current production about 0.1 trillion cubic feet (TCF) per year (Ref. C-2).

The majority of Devonian wells require some form of stimulation to increase production to an economic level. The traditional method involves the detonation of gelled nitroglycerine in the well bore. The formation at the well bore is physically shattered and, after rubble removal, the enlarged bore provides more effective gas communication at the new surface. This approach is relatively inefficient because of the limited radial effect. However, it is comparatively inexpensive and can be profitable in favorable geologic areas.

A conventional technique over the last 10 to 15 years has been hydraulic fracturing. It is recognized as a more effective method of stimulation than well bore shooting. It is also more versatile; portions of favorable zones can be isolated with casings and the fluid directed into them to fracture formations with the highest production potential.

Several advanced techniques are being tested for effectiveness, including massive hydraulic fracturing, cryogenic or gas fracturing, intensive explosions, and deviated well drilling (Ref. C-4). Limited data indicate that advanced technology stimulation can significantly improve current techniques.

Perhaps as important as advances in stimulation methods are advances in exploration techniques. New geological and geophysical approaches have the potential for defining the areas having better naturally fractured shale before any drilling investment is made. Improved logging tools, coring techniques, and interpretation can better define the best intervals for stimulation. Accurate modeling of NG production derived from test data interpretation may eventually lead to optimum matching of stimulation methods with different shale formations (Ref. C-3).

With regard to development constraints, one is the lack of pipelines near some potential production areas. Other constraints are the uncertainty about the resource size, best stimulation method, economics of NG recovery, and competition with conventional NG sources. Finally, despite the large acreage underlain with Devonian shale, over 40 percent cannot be drilled due to urban centers, lakes, waterways, gas storage fields, unavailable leaseholds, depleted producing areas, and various other factors.

C.1.2.3 Geopressured Brines

Although geopressured aquifers have been known to exist for some time, having caused difficulties in drilling for deep oil and gas reservoirs, interest in their commercial potential has been relatively recent. The major, most promising aquifer areas are located along the northwestern rim of the Gulf of Mexico in southern Louisiana and Texas. The potential

area ranges in width from 50 to 70 miles northward from the coast. The basic technology for recovering NG from the geopressured aquifers consists of drilling production wells capable of passing large quantities of gas-bearing water, installing facilities to capture the NG that comes out of the solution at atmospheric conditions, and disposing of the brine. Drilling should be quite similar to conventional gas wells for depths from 12,000 to 17,000 ft, except that larger diameter tubing must be used to accommodate the high water volumes. It is estimated that costs would be about 25 percent higher than conventional gas drilling methods.

Production facilities would consist of large-capacity gas/water separators, compression facilities, brine injection pumps, and multiple, shallow, high-rate disposal wells. Because of the 2-mile or more distance between wells, each would require separate production, disposal, and sales facilities. With improved extraction facilities, it is believed that up to 85 percent of the gas in solution can be recovered, but only 2 to 5 percent of the reservoir's water can be produced before exhausting the reservoir's drive mechanism (Ref. C-3).

Opportunity for the conversion of geothermal energy to electricity is limited. For a 10 percent return on investment in geothermal equipment, the following criteria must be met: (1) minimum brine production rate of 40,000 barrels per day (BPD) per well, (2) minimum surface flowing temperature of 270°F, and (3) minimum life of 10 years at constant production rate. Of 11 prospective reservoirs evaluated in Reference C-3, only five would meet the minimum requirements. These five prospects could generate a total of 19 megawatts of power from eight wells. The same general assessment was made in Reference C-5. Direct use of the low-grade heat contained in the brine for industrial or agricultural applications offers some promise. However, great difficulty can be anticipated in load equalization and in locating plants near the site of brine production (Ref. C-5). References C-3 and C-5 also conclude that the hydraulic energy potential is minor, representing at best less than 2 percent of the NG energy.

There are many technical and economic constraints that will prevent early commercialization of geopressured brines. Because little is known about the geologic and productivity characteristics of potential reservoirs, the number of economic reservoirs is uncertain. There is a paucity of data on the physical and chemical characteristics of the contained waters, such as temperature, pressure, and dissolved contaminants. A very important question is the gas saturation level in the brine. DOE-sponsored wells in Louisiana and Texas indicated the potential for serious downhole corrosion and scaling because of dissolved carbon dioxide. Large volume geopressured water production may result in land subsidence and increased tectonic activity along growth faults. The technical and environmental aspects of disposal of large quantities of brine need to be determined (Ref. C-2).

Until these technological questions are answered, it will be difficult to obtain financing. Financing also remains uncertain for another reason. There is a major legal question as to the ownership of the resource, that is, should it be treated as a mineral interest or separately as geothermal energy. In the former case, owners of the mineral interests may not have the right to produce geothermal energy.

C.1.2.4 Tight Gas Reservoirs

For more than a quarter of a century, large quantities of NG have been known to exist in tight (low-permeability) sandstone formations where the gas flow is too low to support economic recovery using conventional technology. As shown in Figure C-3, the basins containing these formations stretch westward from the Cotton Valley trend in Louisiana through Texas, to the Uinta Basin of Utah, and north through the Northern Great Plains, crossing the border into Canada. Because of the location and formation of the material, this unconventional resource is often termed "western tight sands."

Twenty years ago, interest in tight sands was limited to nuclear scientists who believed that underground nuclear explosions could fragment these formations and provide a method of competitively extracting NG.

Between 1967 and the early 1970s, three nuclear experiments were performed with little success. In the end, low recovery, high costs, and potential environmental problems ruled out using nuclear stimulation.

Figure C-3. Location of Tight Gas Basins in the United States (Ref. C-3)

In 1972, several task groups convened by the Federal Power Commission to study future domestic NG supplies identified massive hydraulic fracturing as a promising technology for developing these low permeability reservoirs. This approach was tested jointly by government and industry in the Piceance Basin of Colorado in 1974 and has since

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become standard practice for extracting gas in low permeability but otherwise favorable geologic formations (Ref. C-4). Commercial production is now about 0.8 TCF annually for western tight sands (Ref. C-2).

In low permeability reservoirs, the rock matrix pore throats are so small and/or sparse that they severely restrict the rate of gas migration into a well, thereby drastically affecting both production rate and cumulative recovery. An example of the comparative production between typical unfractured and fractured tight gas reservoirs and a conventional one is shown in Table C-2. Sometimes the tight reservoirs are highly saturated with water. In addition, the nature of the reservoirs can vary widely. Some are continuous (termed blanket) reservoirs, others are lenticular. These lenses can vary in width, length, thickness, and curvature. Both the blanket and lenticular deposits are usually found dispersed in massive shale or siltstone sections typically from 500 to 3000 ft thick. The technological problems in recovering gas from lenticular sands are considerably more severe than recovery problems in continuous reservoirs (Ref. C-3).

Massive hydraulic fracturing (MHF) is accomplished by pumping a special fluid into the selected formation at sufficient pressure to break the rock. With current technology, MHF treatments typically range in size from 100,000 to 1,000,000 gallons of fracturing fluid with up to 2.5 million pounds of propping agent (a hard, granular material used to keep the fracture open). The fracturing fluids selected for MHF are critical to fracture growth behavior and the cost of the treatment. Currently available fluids are very complex, non-Newtonian mixtures such as gelled water, gelled hydrocarbon, foam, or a hydrocarbon/water emulsion. Their behavior is affected by temperature, shear rate and history, time degradation, and chemical contamination. Rheological properties and proppant transport characteristics cannot presently be predicted with the degree of accuracy required for optimum fracture design. There is evidence that currently available proppants, such as sands, are not being deposited as designed or are being crushed before the fracture has been drained of gas (Ref. C-3).

Table C-2. Production Rates of Conventional and Tight Gas Reservoirs[1] (Ref. C-3).

	PRODUCTION RATE, MMCF/YR		
	CONVENTIONAL @ 10.0 MD[2]	TIGHT @ 0.001 MD[2]	
YEAR	x_F=100 FT[3]	x_F=100 FT[3]	x_F=4,000 FT[3]
1	22,000	21	798
2	3,770	18	437
5	240	16	269
10	6	13	187
20	0	12	137
30	0	11	114
ULTIMATE 30 YR CUMULATIVE	31,700[4]	390	6,015

(1) COMPUTED FOR A TYPICAL 0.65 SPECIFIC GRAVITY GAS IN A 2:1, 1,280-ACRE, RECTANGULAR, 85-FOOT THICK, 250°F RESERVOIR WITH A WELL BORE FLOWING.
(2) PERMEABILITY UNITS, MILLIDARCIES.
(3) x_F (FRACTURE LENGTH, WELL BORE TO TIP) OF 100 FT REFLECTS CURRENT TECHNOLOGY. THE 4000 FT VALUE IS ADVANCED TECHNOLOGY.
(4) RESERVOIR TOTALLY DEPLETED IN 10.5 YEARS.

More than 1000 MHF treatments of several types under many different geological environments have been performed in the last 6 years. Most activity has been in blanket formations, or in lenticular basins where the lenses are large enough to approximate the drainage area of a comparable blanket formation. Inconsistent results in some basins have emphasized the need for technological advancements. With advanced technology, it is postulated that effectively propped fracture lengths on the order of 4000 ft will be possible in all basins; this is a factor of 40 greater than can be done with current technology. In addition, it will be possible to transport proppant farther down the fracture, resulting in more efficient use of fracturing materials and ultimately reducing the cost per unit length. The azimuthal fracture direction will ultimately be

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predictable so that well patterns can be selected to more effectively drain the entire reservoir.

Potential constraints to expanded production of tight gas include (Ref. C-3):

(1) Market demand at the prices necessary to produce the gas may not be available until the late 1980s.

(2) More operators will have to become convinced that the production technology is dependable, the gas resources are available, and the economics are favorable.

(3) Pipeline capacity is a constraint now in many parts of the country.

(4) Investment requirements will be substantial.

C.1.3 Gas Processing

NG is composed primarily of hydrocarbons, methane being the predominant component at concentrations usually in excess of 85 percent by volume. Other hydrocarbons, fractionally small but important, include ethane, propane, butane, and heavier, more complex, molecules. In processing at the NG plant, most of the butane and heavier hydrocarbons, as well as a portion of the ethane and propane, are removed from the gas as natural gas liquids (NGL). Most of the water, hydrogen sulfide (H_2S), carbon dioxide (CO_2), and other impurities found in NG are also removed in processing to meet varying requirements specified by state statutes or transmission line companies. However, nitrogen (N_2) is difficult to remove and may occur at concentrations of 2 or more percent in some consumer NG. Nitrogen causes no difficulty except that it reduces the heating value of the gas (Ref. C-1). As described later, cryogenic processing can be utilized to remove N_2 and to recover additional quantities of valuable ethane.

NG gas is commonly designated in terms of the nature of its occurrence in the ground. It is called nonassociated gas if found in a reservoir that contains only a minimal quantity of crude oil, and either dissolved or associated gas if found in a crude oil reservoir. Dissolved

gas is that portion of the NG dissolved in the crude oil, while associated gas (sometimes termed gas-cap gas) is free gas in contact with the crude oil (Ref. C-1).

The exploration and extraction steps for NG are similar in concept and equipment to those for petroleum, but are not of particular interest for this report other than their overall energy efficiency value of about 96 percent (Ref. C-6). However, once the gas is recovered, processing technologies differ significantly from those for crude oil.

Processing requirements for NG vary widely. NG produced from a nonassociated gas reservoir may require minimal treatment before it is transferred to the transmission line. Conversely, associated gas, dissolved gas, and gas condensates may require full processing before they are marketable. Water droplets and water vapor must be removed from the NG to prevent formation of hydrates, solid snow-like compounds of water and methane. Hydrates form as the result of the cooling which accompanies gas expansion, and can plug valves, metering equipment, and pipelines. In addition, water condensation in the transmission system can promote corrosion if acid-forming gases (H_2S, CO_2) are also present.

Another justification for processing NG is to recover valuable hydrocarbon compounds contained in the gas. Key products like ethane, propane, and butane are worth more as petrochemical feedstocks and specialty fuels than as NG constituents. As naphtha prices have surged upward, petrochemical producers have found that their plants could use NGL even though they were not originally intended to do so. The portion of ethylene produced from gas liquids increased to an estimated 70 percent in 1979 (Ref. C-7). In addition, the heavier hydrocarbons form another important product, natural gasoline; over 66 million gallons per day were recovered in 1979. In that year, there were 772 gas processing plants in the United States, more than in the rest of the world combined (Ref. C-7).

The first processing step occurs in the field where the wellhead gas is generally sent through a single stage vertical shell separator to remove water, sand, drilling mud, and other solids. If the gas stream

comes from a crude oil reservoir, several stages at reduced pressures may be used to recover the gas from oil and condensate fractions. By taking advantage of the differential between wellhead flowing pressures and gathering line pressure, the gas may be cooled, e.g., to 10°F, to recover additional liquid products.

When the NG is very rich, i.e., has a high content of NGL, or has a high sulfur content, a complex processing plant may be necessary and economically desirable. In contrast to field separation, such plants not only separate the gases from the liquid fraction but also split the liquids into fractions. The usual method for recovery of propane, butane and other hydrocarbon liquids from NG streams is known as refrigerated oil absorption; about 35 to 40 percent of the ethane can also be recovered (Refs. C-8 and C-9). These plants consist of an absorption tower, a stripping tower, and distillation towers for separating the products. The absorption oil, a high boiling mineral oil, also absorbs two types of sulfur compounds, mercaptans and thiols, which are otherwise rather difficult to separate.

In order to recover most of the remaining ethane, the gas must be liquefied and fractionated. At the same time, N_2 can be removed to improve the heating value of the gas. The general liquefaction procedure is discussed later in the section on LNG.

Water vapor is probably the most common impurity in NG. Commercial processes for removing water from NG are based on adsorption on activated solid desiccants, or absorption by hygroscopic liquids or reactive solids. The use of hygroscopic liquids, in particular diethylene glycol and triethylene glycol, or mixtures thereof, in an absorption system is generally the most economical approach for dehydrating large volumes of NG. Dehydration plants using solid adsorbents are capable of removing practically all water from NG. Because of their greater drying ability, they may be used as trimmer units for final dehydration. The use of molecular sieves for this duty has the added advantage of simultaneously removing most of the sulfur compounds.

The aqueous amine process is the most widely used method for removing acid constituents, principally H_2S and CO_2, from NG. The usual preferred solutions are 15 to 20 percent by weight of monoethanolamine in water. A weak chemical bond is formed between the acid constituent and the amine at room temperatures, which can be broken and the amine solution regenerated by heating to 230 to 240°F. Elemental sulfur can be recovered from the separated H_2S by well-established processes, to reduce air pollution and for economic reasons.

A combination of the glycol process and the ethanolamine process, known as the glycol-amine process, is widely used in the NG industry. Mixtures of di- or triethylene glycol and monoethanolamine containing about 5 percent water are used as a solvent for simultaneously dehydrating NG gas and removing acid gases. While the latter are removed to very low levels, dehydration is not as effective as when the glycol alone is used.

There are no federal or national specifications for NG transmitted by pipeline or distributed to consumers. State regulations are usually restricted to odorant content, as discussed in Section C.1.4.4. Specifications on minimum or maximum values are usually a part of the contract between the pipeline company and producer, and between the pipeline company and the gas distribution company. According to one gas distributor, even though much gas is supplied under old pipeline contract specifications, actual acceptance requirements are now much tighter (Ref. C-10).

C.1.4 Gas Transmission and Distribution

C.1.4.1 Transmission Pipelines

Gas leaving the processing plant is ready for compression and injection into the national pipeline transmission system, since producing gas fields are often many hundreds of miles from urban centers of use. The United States pipeline system is extensive, as indicated in Table C-3. The first long-distance, all-welded pipeline was constructed in 1925 from northern Louisiana to Beaumont, Texas. The use of acetylene welding to join the pipe lengths solved a serious problem of leakage around the

bolted couplings that had previously been used to join the pipe lengths; some old bolted pipelines lost between 20 and 40 percent of the gas in transit through leakage. Refinements to gas transmission technology since then have primarily been (1) development of larger diameter pipes, up to 48 inches, (2) use of higher tensile strength steel, making higher operating pressures feasible, (3) higher horsepower compressors, and centrifugal compressors with advantages over the older reciprocating compressors, (4) improved pipe welding techniques, (5) automatic ditch digging machines, (6) improved protection against pipe corrosion through coatings and cathodic protection devices, and (7) automated control systems, permitting remote monitoring and regulation of flow (Ref. C-12).

Table C-3. United States Gas Industry Pipeline in Place, 1950 through 1976[1] (Ref. C-11)

	PIPELINE LENGTH, 10^3 MI			
YEAR	FIELD AND GATHERING	TRANSMISSION[2]	DISTRIBUTION	TOTAL
1950	32.8	113.1	241.6	387.5
1955	45.7	145.9	305.1	496.7
1960	55.8	183.7	391.4	630.9
1965	61.7	211.3	494.5	767.5
1970	66.3	252.2	594.8	913.3
1971	66.2	254.8	610.4	931.4
1972	66.9	258.1	623.1	948.1
1973	65.9	263.1	633.8	962.9
1974	66.4	262.2	645.6	974.1
1975	68.5	262.6	648.9	980.0
1976	70.3	258.3	659.1	987.6
STEEL	70.1	254.7	551.3	876.1
PLASTIC[3]	0.1	1.8	45.4	47.2
OTHER	0.1	1.8	62.4	64.3

(1) AT END OF YEAR. INCLUDES HAWAII AFTER 1959 AND ALASKA AFTER 1960. EXCLUDES SERVICE PIPE. NOT ADJUSTED FOR DIAMETER.

(2) INCLUDES UNDERGROUND STORAGE PIPE AFTER 1970. SOME WAS FORMERLY INCLUDED IN FIELD AND GATHERING PIPE. INCLUDED STORAGE PIPE FOR 1971-1976 TOTALS 3.3, 3.4, 4.9, 5.0 AND 5.3 THOUSAND MILES RESPECTIVELY.

(3) INCLUDES FIBERGLASS.

There are two essentials for a NG transmission system: (1) a cross-country right-of-way containing one or more parallel lines of large diameter (12 to 48 inches), thin-wall (usually 0.1 to 0.8 inch) steel pipe laid 2 to 4 feet below the surface, and (2) compressor stations (2500 to 20,000 or more horsepower) located 50 to 100 miles apart. Normally, fuel for the compressor engines is NG taken directly from the pipeline. Metering and regulating stations are located at NG purchasing points and at delivery points which connect the transmission lines with local NG distribution systems. At the delivery points, odorants may be added to the gas.

Most major long-distance transmission lines are more than 500 miles in length, and a few exceed 1500 miles. By 1966, when NG service reached Vermont via Canada, all of the lower 48 states were served with NG. High pressures within the lines are an essential feature of long-distance gas transmission. Pressures in the range of 700 to 1000 pounds per square inch (psi) are common; a few lines operate at pressures over 1000 psi. Figure C-4 shows how much the design capacity of a pipeline can be increased by increasing the pressure at a particular pipe diameter. During normal operations, NG moves through the line at 10 to 25 miles per hour, and drops approximately 3 psi per mile until the next compressor station is reached.

The gas pressure in transmission lines has great expansive energy in addition to the potential chemical energy that could be released through combustion. This contributes to the hazards of pipeline rupture. Serious pipeline accidents, some involving multiple losses of life, have occurred as a result of ruptures. The most frequent causes of pipeline rupture are metal corrosion and careless use of earth-moving equipment. The former can be minimized by the use of coated pipes and cathodic protection, the latter by right-of-way posting and a vigorous public information program. Many aspects of pipeline construction and maintenance are now regulated by the Office of Pipeline Safety within the Department of Transportation (DOT).

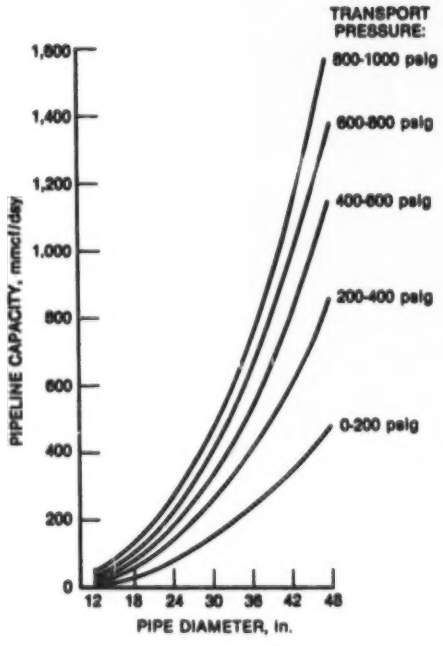

Figure C-4. Effect of Pipe Size and Transmission Pressure on Natural Gas Pipeline Capacity (Ref. C-12)

C.1.4.2 Gas Compression

The size and characteristics of compressor stations are very significant in overall transmission line throughput, the addition of compressor horsepower being one of the options considered as a means of increasing pipeline capacity. Compressors in relay or main line stations are generally of large volume and operate with low compression ratios, usually less than 2. Each station may be equipped with a dozen or more compressors to provide the necessary flexibility for maintenance and load variations. Storage field stations compress trunkline gas for injection into storage wells; these compressors may discharge at pressures up to 4000 psi. Distribution plant stations ordinarily pump NG from a low-pressure storage holder to distribution lines at 20 to 100 psi.

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Auxiliary equipment at compressor stations may include (1) cleaners and filters for inlet and outlet gas (wet or dry types), (2) water cooling system for engines, (3) compressed gas coolers and intercoolers, (4) fuel gas regulatory system, (5) standby generators, (6) compressed air system, (7) lubricating oil purifiers, (8) combustion air filters, (9) emergency shutdown system, (10) facilities for odorant introduction, (11) gas measuring equipment, and (12) remote control devices and communications. Modern compressor stations can be monitored, stopped, started, or adjusted to other loading conditions by computer or manual control from remote locations.

There are two main types of gas compressors, reciprocating and centrifugal. A third type, the rotary blower, is used primarily in distribution systems where the pressure differential is not over 15 psi. Inasmuch as reciprocating gas compressors are long-lived and have been used since the early days of gas pipelines, they are the most commonly found units. Both size limitations of compressor cylinders and efficiency drop-off at low compression ratios (see Fig. C-5) usually preclude series arrangements of reciprocating machines. In parallel operation, each cylinder may handle a small part of the total flow while developing the station's total pressure ratio.

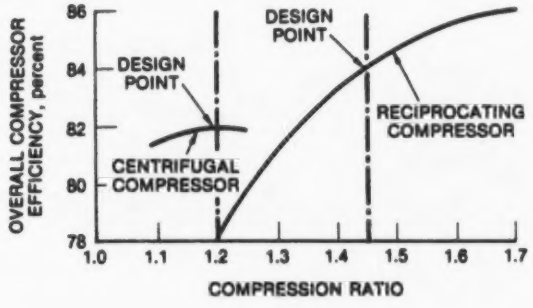

Figure C-5. Comparison of Centrifugal and Reciprocating Compressor Efficiencies (Ref. C-13)

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A reciprocating machine is designed for a certain range of compression ratios through the selection of piston displacement and clearance volume. The clearance volume can either be fixed or variable, depending upon the extent of operating range and the percent of load variation desired. Valve lifting devices also may be used to control compressor capacities, and small variations may be obtained by varying the operating speed. Finally, there are usually several reciprocating units in a station; thus large capacity variations may be accomplished by either adding or subtracting machines (Ref. C-13).

Centrifugal compressors are characterized by few moving parts, relatively low compression ratios, and continuous delivery without cyclic variations. They are inherently high-capacity, low-pressure-ratio machines that lend themselves easily to series arrangements. They are easier to install and automate, and offer lower installation and maintenance costs; however, they consume more energy and offer less operating flexibility than reciprocating compressors (Ref. C-1).

With reference to prime movers, since centrifugal compressors are fundamentally high-speed machines and reciprocating compressors are low-speed machines, certain prime movers are more suited to one type than to the other. Cost and availability of electric power generally limit the application of electric motors. Another drawback is the high cost of variable-speed drives, where required. Also, the maximum speed of motors on 60 cycle current is 3600 rpm, below the operating speed of modern centrifugal compressors.

Steam turbines dominate the field as prime movers in applications requiring 10,000 horsepower and over. High rotary speed, which may be varied according to demands, makes steam turbines well suited for direct connection to centrifugal compressors. A plentiful supply of make-up and cooling water is required. Fuel consumption is relatively high compared with gas engines, about the same as for gas turbines. The latter are also well suited for direct connection to centrifugal compressors. Cooling water needs are low, little auxiliary power is required, and labor

costs are moderate. The primary deficiency is high fuel consumption, particularly at partial loads.

The reciprocating internal combustion gas engine is the leading prime mover for pipeline service. The most popular designs are composite gas engine-reciprocating compressor units, ranging in size from below 100 horsepower to 15,000 horsepower. They can also be used to drive centrifugal compressors, while gas or steam turbines are largely confined to the centrifugal units.

C.1.4.3 Gas Storage

The most effective short-term means of matching capacity with demand are so-called interruptible sales. Interruptible gas is supplied to industrial customers during the summer when demand is low but not during the winter months, when alternative fuel must be used for steam raising or power generation. There are many drawbacks to this approach, and a detailed discussion is inappropriate for this report. Other preferred techniques are, therefore, presented in the following paragraphs.

NG storage facilities have been developed in conjunction with long-distance pipeline systems in order that the pipeline can operate at essentially a constant transmission rate throughout the year. Excess gas, available during periods of low demand in the summer months, is stored for use during peak demand periods in the winter. Operation of the pipeline near its capacity at all times minimizes the unit transportation cost.

There are several storage methods. Normally, NG is stored underground in depleted gas or oil reservoirs. Aquifers, salt domes, and sealed mines have also been used for this purpose. Figure C-6 indicates the location of underground reservoirs in the United States as of 1973. As of early 1981, approximately 400 underground NG storage reservoirs were in operation in 26 states. These reservoirs have a total capacity of 6.8 TCF, of which 3.2 TCF is available for withdrawal.

An underground storage facility must be capable of holding large volumes of gas, must be gas-tight, and must have high deliverability

during withdrawal. In addition, the storage area should normally be close to the market served by the pipeline. With minor exceptions, the underground facility is not a large cavern but rather is a formation of sandstone or other porous rock. Permeability must be sufficient to allow high rates of gas injection and withdrawal. For some of the major cities of the eastern seaboard and the Midwest, there are no suitable nearby NG storage areas, and winter gas deliveries from storage must be transported by pipeline as much as 200 or more miles (Ref. C-12).

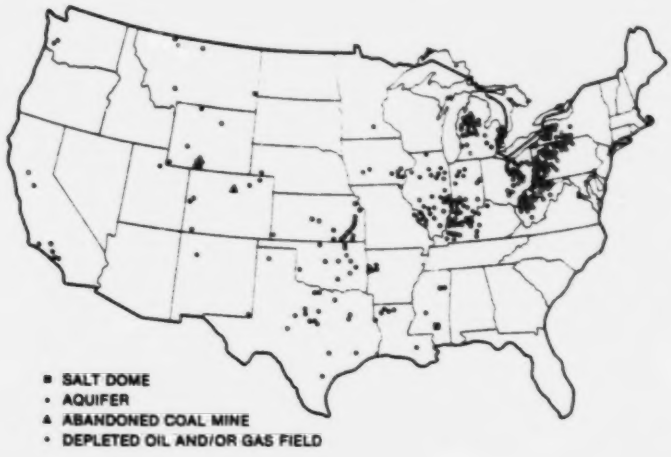

Figure C-6. Location of Underground Gas Storage Reservoirs in the United States in 1973 (Ref. C-12)

One-third to one-half of the NG in an underground storage reservoir is always kept there and is known as cushion gas. This cushion helps to maintain the storage pressure required to make large deliveries on cold winter days. Although this gas may ultimately be recovered, it represents a tie-up of capital during the active life of the storage project. Pressures in storage fields vary widely from field to field, and in the same field at various times in the injection-withdrawal cycle. The deliverability of the storage field drops rapidly as the pressure declines. Thus, deliverability is very good during the early portion of the winter

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heating season but relatively poor in late February and March. One field in Ohio, as an example, has a daily delivery rate of 25 million scf (mmscf) per day when it is filled at 1000 psi, but later in the heating season as the driving pressure decreases, the daily rate drops to 8 mmscf at 500 psi and only 4 mmscf at 400 psi (Ref. C-12).

Underground storage of gas has a good safety record; there has never been an in-earth explosion of an underground storage reservoir (Ref. C-12). The Federal Power Commission maintains detailed data on underground facilities operated by interstate pipeline companies, representing about 55 percent of the total storage capacity. The remaining capacity is operated primarily by gas distribution companies and to a lesser extent by intrastate pipeline companies.

The flow diagram for a typical above-ground processing facility associated with an underground reservoir is shown in Figure C-7. During the gas injection phase, NG is withdrawn from the gas transmission supply line, compressed, and injected into the storage reservoir through injection wells. Injection pressures vary, depending on the storage pressure characteristics of the specific reservoir, which in turn is a function of the depth of the reservoir. Both piston-driven reciprocating compressors and gas-turbine-powered centrifugal compressors are used for injecting the gas into the reservoir. The size and number of compressors depend on the capacity of the reservoir and the time available to store the gas. Typical machines of the reciprocating type are two-stage devices having horsepower ratings ranging from 2000 to 5000. The centrifugal machines contain 15 to 17 stages and have ratings of from 3000 to 10,000 horsepower. Compressor prime movers are typically NG powered.

NG is withdrawn from the reservoir through either separate withdrawal wells or combination injection/withdrawal wells and is transferred to the central processing plant. Gas processing following withdrawal includes the removal of hydrocarbons (in the case of depleted oil/gas or oil fields), desulfurization if required, and dehydration. Compression of the NG prior to injection into the transmission line may be required if the reservoir storage pressure is lower than the transmission line pressure.

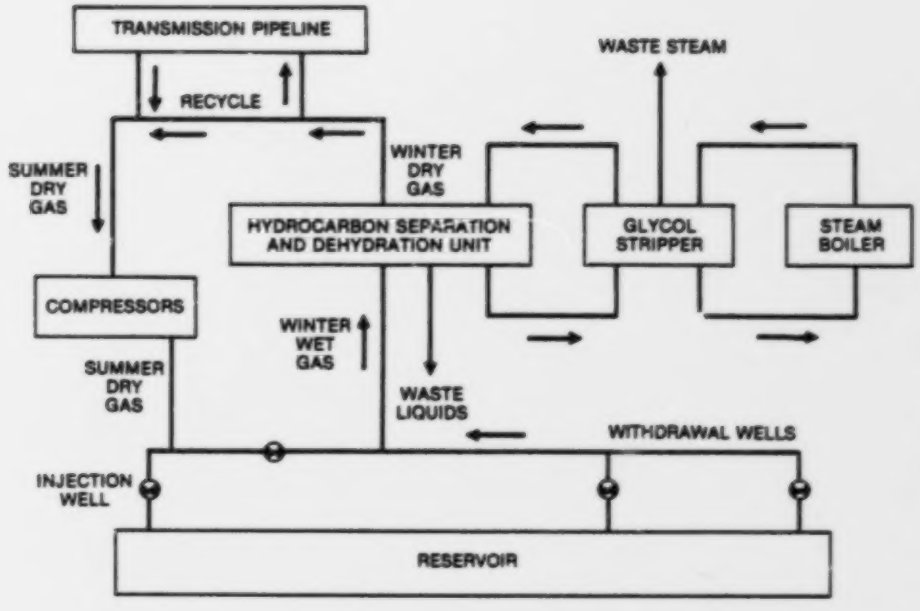

Figure C-7. Flow Diagram for an Underground Natural Gas Storage System (Ref. C-14)

In addition to underground reservoirs, several other methods for storing NG are in use. Aboveground tanks, known as gas holders, are also common. However, since tanks cannot hold large volumes of gas, this storage mode is used primarily to meet daily peak demands in local distribution systems. Furthermore, the cost of low-pressure gas holders, in relation to their capacity, is high and they are aesthetically unattractive.

Storage of gas in the form of LNG is an important technique to accommodate peak demands of up to a few days' duration. Such peak shaving plants are widely used in the United States, with liquefaction capacities ranging from 0.5 to about 20 mmscf per day, and storage capacities between 100 and 300 times the daily liquefaction capability. A particular form is the satellite LNG facility. This generally consists of a storage tank, vaporizer, and odorizer plant located some distance from a much larger

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peak-shaving facility. The tank is filled by road, rail, or barge. The satellite plants usually operate unattended, with the flow of LNG to the vaporizer regulated by the gas pressure in the distribution grid (Ref. C-15).

C.1.4.4 Gas Distribution

The local distribution system is the means of delivering gas to the ultimate consumer. The system consists of a network of mains with valves, regulators, meters, and other equipment which serve to transmit, control, and measure the gas flow to the individual customers. NG enters local distribution systems at points called city gate stations or city border stations. Although most communities have only one city gate station, some large cities have high-pressure loops at 400 to 500 psi, with several stations from which the gas enters the local system. The NG usually enters at 100 to 150 psi.

The lines serving individual residential or commercial customers contain NG at pressures in the range of 0.2 to 0.4 psig supplied from mains operating in the 25 to 60 psig range. Individual house regulators are used in modern practice. Large-volume commercial and industrial customers (2500 scf per hour or more) are normally served by individual direct lines from the high-pressure system or transmission lines.

Any gas distributed to customers through gas mains, or used for domestic purposes in compressor plants, must have an odor sufficient to make it detectable. The purpose is to protect the customer, aid in detecting leaks throughout the distribution system, and to meet regulations established by over half the states. In general, it is required that the gas be detectable at concentrations of not over 1 volume percent in air, which is approximately one-fifth the lower explosive limit; however, several states have limits as low as 0.15 percent by volume. Inasmuch as detectability is a subjective parameter that varies widely within the population, the many gas companies in the United States odorize to different degrees in interpreting these requirements.

Present-day commercial odorants contain one or more of the mercaptans, aliphatic sulfides, and cyclic carbon-sulfur ring compounds. Most odorants have a freezing point between 10°F and -50°F and are added at a rate between 0.25 and 1.5 pound per mmscf. The odorant should have a distinctive odor, be inert and noncorrosive, nontoxic, economical, and burn completely to nonirritating products. It should be noted that some NG, e.g., from California, has a sufficient natural odor that a commercial odorant often is not needed.

C.1.5 Liquefied Natural Gas

Liquefaction is a means of preparing NG for either shipment or storage. One cubic foot of liquid methane at -260°F and 1 atmosphere is the equivalent of approximately 630 scf of gas. The removal of about 16 Btu converts a cubic foot of gas at 40°F to liquid at -260°F. The heat of vaporization of LNG is approximately 10 Btu per scf of gas formed. Other useful quantities include (1) 6575 Btu to vaporize a cubic foot of liquid methane (25.9 lb) (2) 20 lb of steam (1000 Btu per lb) to vaporize enough liquid methane to form 1000 scf of gas, and (3) approximately 86,000 Btu higher heating value (HHV) from a gallon of LNG.

Gas liquefaction and storage is a valuable means of meeting periodic, temporary gas shortages; such an application is termed peak shaving and has been previously described. Most LNG plants in the United States are of this type. The other application of LNG is for baseload gas supplies where NG in surplus areas is liquefied for long distance shipment, usually in specially constructed ships, to areas of deficiency. Although some LNG has been imported to the United States for regasification and pipeline injection, the only baseload liquefaction plant in this country is on the Kenai Peninsula, Alaska, where local NG is liquefied for shipment to Japan.

In the following subsections, liquefaction processes, storage, transport, and regasification are briefly reviewed.

C.1.5.1 Liquefaction Processes

Before liquefaction can proceed, certain constituents, particularly CO_2, H_2S, and water vapor (H_2O), must be reduced to low levels or they will solidify and eventually plug the liquefaction unit. If the NG comes from a transmission pipeline, only minimum pretreatment may be needed. In other cases, where essentially wellhead gas is the plant feedstock, the gas processing procedure as described in Section C.1.3 is required. Generally, it is desirable that the H_2O content of the gas should be less than 1 part per million (ppm) by volume, CO_2 less than 50 ppm, and H_2S a maximum of 3 ppm (Ref. C-15).

A molecular sieve system, shown schematically in Figure C-8, will simultaneously remove H_2O, CO_2, and any traces of H_2S, odorants, and heavy hydrocarbons. Incoming gas flows downward through one tower, where water is removed in the upper section of the bed and CO_2 and other impurities in the lower section. Effluent NG typically contains less than 20 ppm of CO_2 and less than 1 ppm of H_2O. The adsorber towers are designed for short cycle times of less than 2 hours, with automatic switching valves for unattended operation. Simultaneous regeneration of the second tower is accomplished using heated process gas flowing upward through the saturated bed to desorb the impurities. The exit gas can be sent back into the pipeline or used locally in the plant. The bed is then cooled by bypassing the heater. A small, micron-size solids filter is usually installed downstream of the dry-bed system, to ensure removal of trace quantities of adsorbent dust which might be present in the feed stream to the liquefaction section.

In principle, liquefaction of NG requires the removal of energy in the form of sensible and latent heat. There are several processes available, and various modifications of each. The selection of the best process for a particular plant is based primarily on investment and life-cycle costs, considering the feed stream characteristics, sensitivity to ambient conditions, start-up and shut-down times, critical process parameters, and demonstrated reliability in operating plants.

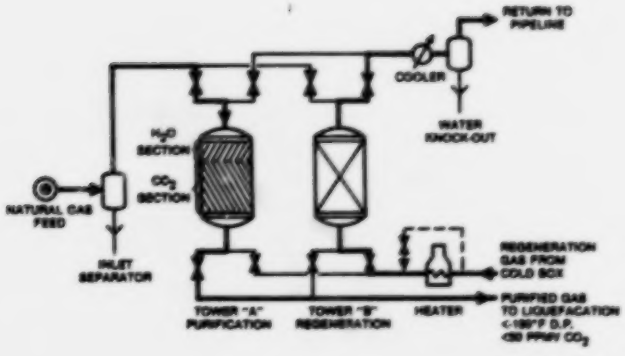

Figure C-8. Flow Diagram for a Molecular Sieve System for Combined Natural Gas Dehydration and Carbon Dioxide Removal (Ref. C-16)

There are two basic types of liquefaction cycles: (1) those which depend mainly upon the compression and expansion of the NG to be liquefied, either using the Joule-Thomson effect, an expansion engine, or a combination thereof; and (2) cascade systems, which depend mainly upon auxiliary refrigerants, and use either vapor recompression or an expansion engine for cooling. The following discussion presents only the principles of each generic process. Detailed descriptions are available in the literature, particularly in patents dealing with ingenious combinations of the basic concepts or improved heat transfer equipment.

Within the LNG industry, the first of the liquefaction cycles mentioned above is termed the expander cycle. Figure C-9 illustrates the essential features of this cycle. Treated feed gas, along with recycle flash gas, is compressed and flows to the heat exchanger. Some of the high-pressure gas is withdrawn at an intermediate point in the exchanger and expanded nearly isentropically through either a turbine[2] or

[2] Modern LNG expander liquefaction plants use expansion turbines rather than reciprocating engines (Ref. C-15).

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reciprocating engine to produce a cooling effect. The expanded cold gas passes to the cold end of the exchanger and is warmed before being returned to the compressor. The cooled high-pressure gas undergoes a Joule-Thomson expansion through a valve and flashes into a phase separator. The liquid product is removed and the vapors are warmed and recycled. External work is performed by the expander, either in the form of electrical generation, gas compression, or liquid pumping, depending on the method of loading the expander (Ref. C-16).

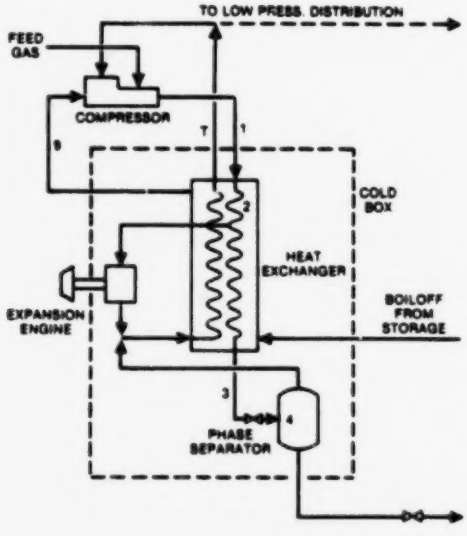

Figure C-9. Flow Diagram for a Liquefaction Cycle Using a Simple Expansion Engine (Ref. C-16)

The cascade cycle is representative of the second type of liquefaction system and comes in many variations. Basically, it consists of a series of separate refrigerants to cool the NG to progressively lower temperatures until finally the dew point is reached. Each refrigerant operates on the vapor recompression cycle depicted in Figure C-10. Vaporization between points 3 and 4 provides cooling at low temperature T_2 and

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low pressure P_2. The vapor is compressed and thereby heated, and the heat is subsequently rejected at a higher temperature with reliquefaction of the refrigerant. A single refrigerant will, as a rule, allow cooling of the main stream by 110 to 160°F. Since methane must be cooled from as high as 100°F to -259°F, conventional LNG cascades usually employ three refrigerants in series, e.g., propane, ethylene and methane. Cycle efficiency can be improved by the use of additional refrigerants to more closely approach the reversible ideal cycle, but the added cost does not justify the energy savings (Refs. C-15 and C-16).

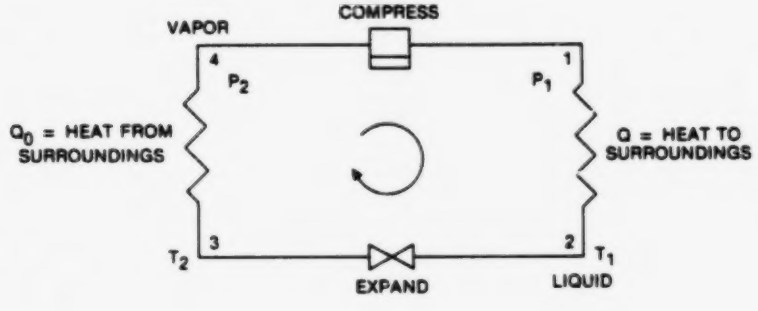

Figure C-10. Flow Diagram for a Refrigeration Cycle Using One Refrigerant (Ref. C-16)

A typical cascade cycle flowsheet is shown in Figure C-11. The NG at a pressure of about 500 psi is combined with gas recycled from compressor CP-1 and divided into two streams. One stream is cooled in heat exchanger E-1 against low-pressure NG flash vapors. The other stream passes through E-3A, E-3B, and E-2A where it is cooled by evaporating propane and ethylene. The two flows combine and are liquefied in condenser CD-1 by evaporating ethylene. The high pressure liquid is expanded twice into phase separators PS-1 and PS-2, then sent to storage. The flash vapors are used to cool the incoming gas in exchanger E-1. The heat removed from the NG is rejected to cooling water at the various compressors, particularly at CD-3 where propane is liquefied. Each refrigerant in the

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standard cascade operates in its own closed cycle without intermixing at any point.

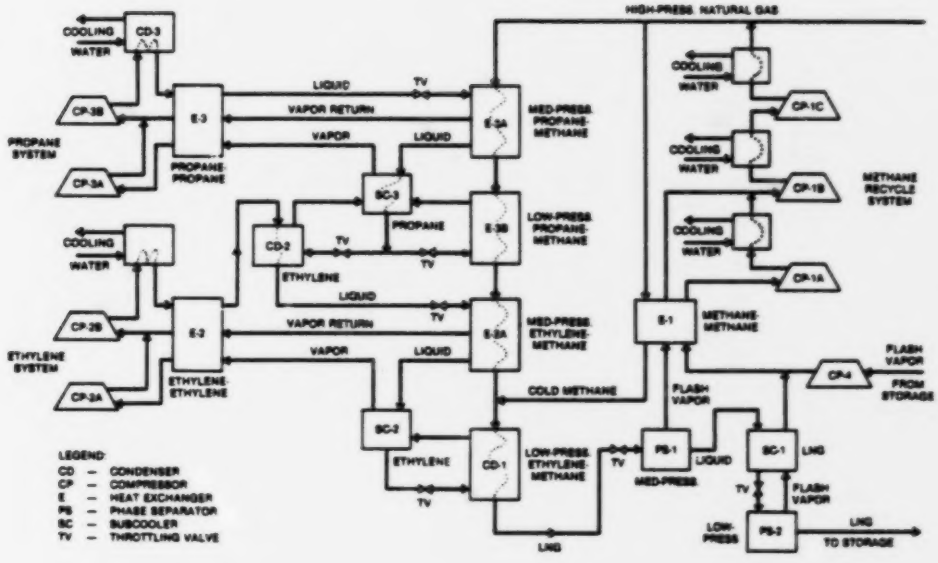

Figure C-11. Flow Diagram for a Cascade Liquefaction Cycle (Ref. C-16)

A variation of the cascade cycle involves the circulation of a single refrigerant stream. The constituents of the refrigerant stream are usually components of the NG, such as butane, propane, ethane, methane, and nitrogen. The NG feed is cooled and condensed through a series of heat exchangers as depicted in Figure C-12.

The mixed refrigerant is compressed by the compressor C-1, with the heat of compression removed by water in an intercooler and after-cooler. The refrigerant is thereby partially condensed and the two phases are separated in the separator S-1. The liquid and vapor flow in separate lines to the exchanger E-1 where heat is transferred to the returning refrigerant. The vapor is again partially condensed and flows to the

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separator S-2. The liquid phase from S-1 is subcooled in E-1 and reduced in pressure, then added to the refrigerant flowing back to the compressor to provide refrigeration for the three counterflowing streams in E-1. In similar manner, the liquid and vapor from S-2 pass through E-2 to be further cooled. The vapor stream is totally condensed in the E-2 and E-3 exchangers and reduced in pressure to supply the final level of refrigeration in flowing back through E-3. Meanwhile, the NG feed is successively cooled and condensed as it passes through the three exchangers.

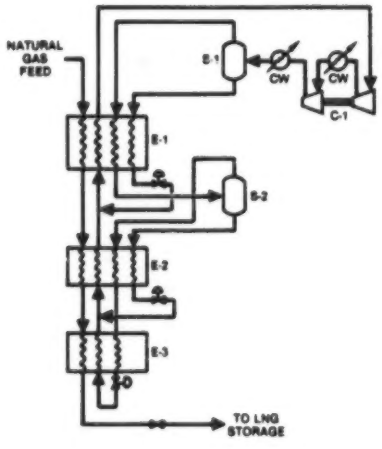

Figure C-12. Flow Diagram for a Mixed Refrigerant Cycle (Ref. C-16)

Although the three processes described above are the primary ones in use, there are many other, often proprietary, systems. Among these are the Propane-Mixed Refrigerant cycle, which uses propane as the initial high-temperature refrigerant, and the Stirling cycle. Such processes are not discussed here, as they are either straightforward variations of the basic concepts or are little used at present.

A comparison of the three liquefaction approaches is difficult because results depend heavily on specific plant parameters, such as

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capacity, feed characteristics, ambient weather variations, gas cost, and financing availability and cost. The expander cycle would appear to be most efficient because work is extracted during expansion, as contrasted with the completely irreversible Joule-Thomson systems. However, approximately 8 to 16 volumes of gas must be expanded for each volume of NG liquefied. This requires a substantial amount of recirculation and recompression and, therefore, higher energy than the more complex cascade cycles (Ref. C-16). A recent comparison referred to in Reference C-15 claimed that well designed cascades operate at the same, if not higher, efficiency than turbine expanders.

The main advantage of the expander cycle is simplicity, which can result in lower capital costs for small plants. The cycle has definite application where NG is already being reduced in pressure from transmission lines to distribution mains or power stations. In such situations, it is possible to utilize this energy in the expansion turbine for refrigeration. Moreover, the expanded vapors can be sent to the low-pressure distribution system or power station, thus reducing or eliminating recycle compression (Ref. C-16).

The main advantages of the modified or mixed refrigerant cascade system compared with a conventional cascade are the smaller number of compressors and heat exchangers required, together with simpler piping. Instrumentation, space requirements, and capital investments are claimed to be reduced. Furthermore, there is no need for storage of make-up refrigerants since they may be extracted from the NG feed. However, the mixed refrigerant process has little flexibility, and thus the original plant design is critically important (Ref. C-15). In Reference C-17, optimized cascade, mixed refrigerant, and propane-mixed refrigerant processes were compared. Among the five primary evaluation factors of investment cost, operating cost, flexibility, and startup and onstream time, the cascade process surpassed the other two cycles on all factors except investment cost where they were all considered to be equal.

C.1.5.2 LNG Storage

Both domestically produced and imported LNG require large-volume storage facilities. In the case of peak-shaving applications, storage of 100 to 300 times daily plant output is needed near metropolitan areas to meet winter demands. For this purpose, LNG is stored for relatively long periods of time and used during only a few days of the winter. Consequently, heat influx must be held to a minimum. At ports receiving overseas LNG, the storage facility is essentially a surge tank, smoothing out the fuel delivery operations to meet the baseload demand. In this case, storage tanks are much larger than for peak-load facilities. Also, it is usually unnecessary to preserve the LNG in the tank for long periods, since it is passed on to distribution within a relatively short time after receipt. Consequently, higher heat influx resulting in greater boiloff rates can be tolerated (Ref. C-16).

Whether peak-shaving or baseload operations are involved, a large portion of facility costs is for LNG storage. Also, the large volume of storage associated with LNG plants represents a high concentration of energy. Thus, for economic and reliability reasons, considerable research and development expenditures have been made relative to storage concepts. The primary designs reviewed in the following paragraphs fall into the categories of metal tanks, prestressed concrete vessels, frozen in-ground holes, and mined caverns, with major emphasis on the metal tanks.

Aboveground, near-atmospheric-pressure, double-wall metal tanks have been used successfully for many years for LNG service. These tanks have generally been flat-bottomed, cylindrical, dome-roof units with an outer shell of carbon steel and an inner tank of usually 9 percent nickel steel or aluminum. Insulation between the two shells usually consists of perlite powder in a nitrogen or NG atmosphere to exclude moisture. Below the tank bottom, insulation must be of the load-carrying variety. The weight of the tanks is insufficient to ensure stability and they must be bolted to the foundation to prevent lifting and movement when they are filled with gas only.

It is important to prevent extremes of temperature affecting the foundation. Freezing and subsequent melting of the soil below the tank are avoided by a combination of tank lagging and heating coils in the sand. Piping connections to an LNG tank are kept to a minimum and, where possible, are made through the top of the tank so that external pipe damage would not result in liquid drainage. A connection at the top is required to carry boiloff gases back to the refrigeration system or to a low-pressure distribution line.

Perlite insulation is not resilient and compacts in use. Due to changes in storage and ambient temperatures, differential movement occurs between the inner and outer tanks, further compacting the loose perlite. The usual method of control is to cover the external surfaces of the inner tank, and in some cases the internal surfaces of the outer tank, with resilient blankets of fiberglass. These blankets maintain a firm bearing against the loose perlite while taking up the differential movement between the tank walls and the perlite.

Other insulating materials can be used, including polyurethane foam, expanded polystyrene, and similar materials. However, when taking into consideration the cost of these insulating materials and their installation, the perlite system has a substantial economic advantage.

In addition to cylindrical metal tanks, spherical tanks with perlite insulation under vacuum are frequently used at satellite installations where the LNG may be stored for long periods and a very efficient installation is desired. Often the inner tank is operated at pressures up to 300 psia in order to eliminate or reduce venting, or to match the pressure of a gas distribution or transmission line to eliminate the need for a boiloff compressor.

Turning to other LNG tankage options, two prestressed concrete tank designs have been developed in the United States, and such tanks are now used in various locations around the world. Generally, they are built in very large sizes and, therefore, are of limited interest within the scope of this study. However, a few of the design features are briefly described here.

While all tanks use some type of gas-tight metal membrane to prevent leakage, the arrangement of concrete wall, metal barrier, and insulation differ among the various designs. In a tank developed by the American Gas Association (AGA) and the Institute of Gas Technology (IGT), the concrete contacts the LNG and is backed by a stainless steel barrier and Foamglas insulation. In another approach, developed by Texas Eastern Transmission Corporation and the Battelle Memorial Institute, the metal barrier contacts the LNG and is backed by insulation and then a prestressed concrete wall. Two tanks built in Barcelona, Spain, in 1969 represent a combination of these approaches. The floor is 9 percent nickel steel backed by polyurethane insulation, but the walls are concrete backed by carbon steel and perlite powder insulation.

Both above- and below-ground prestressed tank locations are theoretically possible, but only the aboveground tanks have been successful to date. The below-ground design has the advantage of replacing part of the insulation by the soil; in addition, it does not require a retaining dike and is more acceptable aesthetically.

Frozen-ground and cavern storage techniques appear simple in concept, but have achieved little success in operation. In the former approach, a pit is excavated in water-saturated soil or rock by first freezing a ring of soil with refrigerant circulated through buried pipes. Of four storage facilities built around the world, two smaller peak-shaving sites were abandoned due to excessive boil-off rates, while two large baseload facilities continue in service.

The use of mined or natural caverns, suitably lined to prevent LNG seepage into the ground, is even less common than successful in-ground storage. While mined caverns can be located in appropriate areas, provided suitable geological strata are present, natural caverns rarely occur in locations where there is a demand for the stored gas. One instance of such storage in Massachusetts failed because it proved impractical to seal the leaks in the cavern wall (Ref. C-15). Some concern for the structural integrity and thermal efficiency of mined caverns may also be a factor

which has slowed the commercialization of the mined cavern concept (Ref. C-16).

C.1.5.3 LNG Transport

Bulk movement of LNG has limited application within the scope of this study and therefore is treated only briefly here. Importation of LNG by ship from overseas gas fields is an established technology but presently a minor supply source for the United States. Therefore, techniques for overland, or inland waterway, movement of LNG from domestic liquefaction plants, or possibly import terminals, to satellite storage facilities at or near the point of fleet use is addressed.

Overland transportation of LNG can be accomplished in mobile tanks or pipelines. Historically, short-distance, large-volume transport has been through insulated pipelines, e.g., from liquefaction plant to storage, or in loading or unloading tankers. Smaller volumes are moved over longer distances in insulated over-the-road tank trucks or railway cars. No barges have been used for the commercial transport of LNG on inland waterways, but the concept has been studied for several applications. The need for increasing quantities of LNG at remote locations has provided the impetus for the development of all of these transport systems. Each is briefly examined in the following paragraphs.

Prior to 1969, only a few small-scale highway movements of LNG had been made in the United States, using liquid nitrogen equipment. Equipment designed and fabricated specifically for LNG service has been developed since then. These truck trailers nevertheless retain many of the design features of traditional nitrogen or oxygen trailers, thereby incorporating reliability and safety concepts developed through years of cryogenic experience. Figure C-13 shows a cutaway view of such a trailer. These trailers have a maximum capacity of about 10,000 gallons, and are volume- rather than weight-limited due to the relatively low density of the liquefied gas (3.54 pounds per gallon). At the point of use, the liquid can be transferred to a storage tank or vaporized and sent directly into a pipeline. In either case, the trailer can be emptied by a

transfer pump or by vaporizing a small quantity of liquid to pressurize the tank.

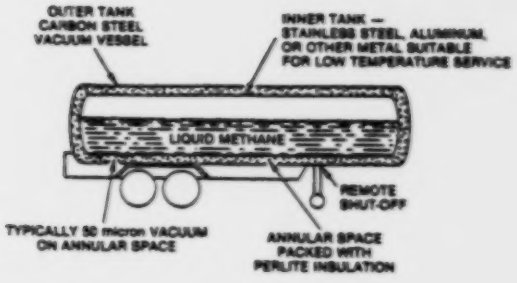

Figure C-13. Schematic Cross Section of a Liquid Methane Trailer (Ref. C-16)

Railway tank cars for LNG are a more recent development, although rail movement of other cryogens has been carried on for many years. For the economics to favor rail car distribution over tank trailer, the distance between the liquefaction plant and the point of delivery needs to be reasonably long and the quantity fairly large (Ref. C-16). In order to avoid venting the combustible vapors during transport, the rail car insulation must be very efficient. In a current standard United States design for a rail car carrying 55 tons (31,000 gallons) of LNG, the internal pressure rise over a period of 40 days amounts to only 30 psi (Ref. C-15).

As far as can be ascertained, no LNG barges are operating in the United States at this time. There was interest several years ago in transporting LNG up the Mississippi to Chicago for use by Chicago stockyards. At least one barge was constructed according to a special design. It had five tanks, each 20 feet in diameter by 20 feet high, insulated internally with balsa wood, similar to the first LNG ship, the Methane Pioneer. A series of tests indicated that the balsa wood was wetted by the liquid, with a consequent reduction in its insulation value. Later preliminary designs have resorted to insulated stainless

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steel or aluminum containers of roughly the same dimensions as the barge's cargo compartment.

Present applications of cryogenic piping for LNG are limited to in-plant transfers at the liquefaction facility and ship-to-shore movements at shipping and receiving terminals. Studies of LNG pipelines over 1000 miles long have been made for Siberia and Alaska/Northern Canada applications. Among the many advantages of transporting liquid rather than gas is the fact that the same size pipe (but designed for low pressures) can carry about 2.5 times as much NG in liquid form for the same pressure drop. There are, of course, many technical and economic problems. Mild steel cannot be used; both nickel steel and aluminum have been considered. Thermal contraction is a major consideration that must be dealt with. Vacuum-jacketed insulation has a thermal conductivity less than 1 percent of that of conventional insulation, but may cost five to ten times more. Polyurethane foam appears to be the most practical insulation, but requires an effective vapor barrier.

For intermediate-distance LNG pipelines, such as from a liquefaction plant to a satellite installation, it is much more economical to send a tank trailer out when required than to install an expensive pipeline with a poor load factor. However, this conclusion only applies when the satellite facility is expected to be used for peak shaving on an occasional basis. If the installation were designed for fueling automotive fleets at a high load factor, the economics might turn in favor of the pipeline.

C.1.5.4 LNG Vaporization

Bulk vaporization of LNG to supply gas mains is not of particular interest in the context of this study. LNG on board the vehicle can be vaporized as described in Volume II, Section 2. Therefore, while it is recognized that vaporization is an integral and important part of LNG utilization, further discussion at this point is unnecessary.

C.1.6 Energy Efficiency

Supply chain energy efficiencies from resource to vehicle are important inputs in assessing the overall resource energy consumption per vehicle-mile for the several alternative fuels evaluated in this study. Therefore, it is appropriate to conclude this review of NG production processes with a compilation of representative energy efficiency values for each major step. The efficiences are based on total energy input and output, without regard to the form of the energy. Inasmuch as this section has focused on the bulk or wholesale supply of NG or LNG, not all the final operations to the point of vehicle fueling are included here. The limits will be clearer from a discussion of Table C-4, which summarizes the supply system efficiencies.

Table C-4. Natural Gas Supply System Efficiencies(1)

SUPPLY STEP	STEP EFFICIENCY CNG	LNG
EXTRACTION/GATHERING	0.964	0.964
PROCESSING(2)	0.968	0.968
PIPELINE TRANSPORT	0.95	0.95
STORAGE(3)	0.996	NA
GAS DISTRIBUTION	0.993	NA
GAS LIQUEFACTION	NA	0.86

(1) TYPICAL OF DOMESTIC GAS PRODUCTION.
(2) NG LIQUIDS PLANT.
(3) UNDERGROUND OR GAS HOLDERS.

Efficiencies of CNG and LNG are identical for the first three steps, viz., gas extraction and field gathering; processing for cleanup and removal of NGL; and pipeline transport, assumed to be 1000 miles from the Gulf Coast to Illinois (Ref. C-6). At the end of the transmission line, it is assumed that the NG is either liquefied at a central

metropolitan plant, or enters and leaves a storage facility and is distributed in city mains. Gas storage efficiency is taken from Reference C-1, while distribution efficiency is from Reference C-6. Note that the efficiencies for CNG in Table C-4 do not include final high-pressure compression into vehicle storage tanks, since this is a local operation at the fueling site and is covered in Volume II, Section 4. Likewise, distribution of LNG to the fleet fueling site and the fueling operation itself are downstream operations from the production plant and are also covered in Section 4.

The 86 percent liquefaction efficiency value is judged to be a reasonable average number based on approximate values quoted by various gas company experts contacted by telephone. Few efficiency values were found in the literature, probably due to the proprietary nature of most of the liquefaction processes.

C.2 SYNTHETIC NATURAL GAS

Methane, the primary constituent of NG, can be manufactured synthetically from a variety of organic materials, ranging from solid fossil fuels to petroleum fractions and urban wastes. The resulting gas, after proper purification, can be substituted for, and mixed with, NG for all purposes. The largest potential source of synthetic (or substitute) natural gas (SNG) is from gasification of the tremendous resources of United States coal, but other resources may eventually make significant contributions, at least at the local level. To a very limited extent, in the case of landfill gas and anaerobic digestion of sewage, such conversion and utilization are ongoing today.

Gasification products are categorized as low-Btu, medium-Btu, and high-Btu gases. Low-Btu gas, which has an HHV of 100 to 250 Btu per scf, results when air, used in the gasification process, produces a gas consisting mostly of carbon monoxide (CO), hydrogen (H_2), and nitrogen (N_2). When oxygen (O_2) is used rather than air, N_2 diluent is not introduced. The resulting gas, called medium-Btu gas, has a calorific value of 300 to 750 Btu per scf. Such gas, if of proper composition, can be used as feedstock to a methanol synthesis unit, as described in Section C.3.

Finally, an additional step, called methanation, by which the CO and H_2 in the gas are catalytically reacted to form methane, results in the production of high-Btu gas with a heating value above about 900 Btu per scf. Only the high-Btu gas is addressed in this section.

The initial focus is the thermal gasification of coal because it represents the largest resource base. Most process development has centered around coal, and utilization of other feedstocks, e.g., wood, represents only minor perturbations of coal gasification technology. In the case of other resources, particularly the various types of urban waste, microbial conversion can replace thermal gasification as the prime conversion technique and this approach also is discussed.

There are many economic, technical, and environmental constraints to large-scale generation of SNG, some of which are addressed below. These factors probably militate against major SNG gas supplies before the 1990s. Nevertheless, inasmuch as almost all forecasts of NG supply include significant dependence on SNG at some point in time, it is necessary that the topic be covered in this report.

C.2.1 Coal Gasification

The three primary ingredients needed to chemically synthesize gas from coal are carbon, H_2, and O_2. Coal provides the carbon and some of the H_2. Steam is the most commonly used source of supplemental H_2, although H_2 is sometimes introduced directly from an external source. Oxygen is supplied as either air or pure O_2 obtained from the fractionation of liquefied air. Heat can be added either directly by combusting a portion of the coal inside the gasifier or indirectly by hot pebbles or ceramic balls from an external source.

Figure C-14 shows the major steps in the production of high-Btu gas: coal preparation and pretreatment, gasification, shift conversion and cleanup, and methanation. Each of these steps is discussed as to chemical changes and equipment designs for the major processes. An alternative method of gasification, underground or in situ, is described at the end of this section.

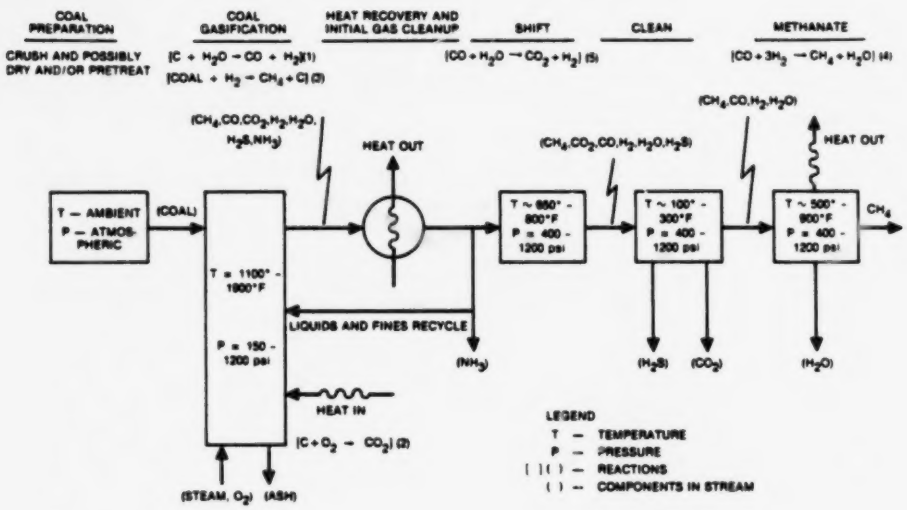

Figure C-14. Block Diagram of Fundamental Gasification Steps for Coal-To-Pipeline Gas Processes (Ref. C-18)

All gasification processes require some preparation of the coal feedstock. This step involves crushing and grinding the coal to a suitably small size so that it can be handled in the gasifier unit. Because some coals contain 30 percent or more moisture, the coal may also be dried for those processes in which a dry feed is desirable. With some coals, a mild oxidation treatment might be needed to prevent the coal particles from agglomerating in the reactor.

After preparation, the coal is fed to the gasification reactor, the heart of the coal conversion process. Although some processes add H_2 from an external source to the gasifier (termed hydrogasification), more frequently the steam-carbon reaction, shown as Reaction 1 in Figure C-14, is used to produce H_2. This endothermic reaction requires heat, some of which comes from Reaction 3, the devolatilization and destructive hydrogenation of the coal. Additional heat must be added, the method varying from process to process. Direct heat (Reaction 2) is more thermally efficient but requires expensive O_2 if a high-Btu gas, not diluted by N_2,

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is desired. Indirect heating using molten salts, dolomite solids, molten slag, pebbles, etc., introduces additional materials requirements and complicates the gasification process.

Control of reactor temperature and pressure is important in determining the products and overall efficiency. Temperatures in the 1900 to 2500°F range produce primarily H_2, CO, and CO_2, termed synthesis gas, with little methane. Although the synthesis gas is ideal for conversion to methanol, it is an inefficient way to produce methane. Consequently, gasifier temperatures are typically kept in the 1100 to 1900°F range to maximize methane formation (Ref. C-18).

Gasification systems may be operated either at high pressure or at atmospheric pressure. The main advantages gained from pressurizing are (1) improvement in the quality of product gas, (2) maximization of the hydrogasification reaction, (3) reduction of equipment size, and (4) elimination of the need to separately compress the SNG before introducing it into a pipeline (Ref. C-1).

In addition to converting the carbon or carbon compounds in the coal to methane, H_2 in the gasifier reacts with coal impurities to form gaseous compounds that can be more easily removed downstream. Such typical impurities as sulfur, N_2, and O_2 react with H_2 to form H_2S, ammonia (NH_3), and H_2O, respectively.

Returning to the process schematic of Figure C-14, the raw gas from the gasifier is cooled and scrubbed to remove particulates and heavy (liquid) hydrocarbons, both of which can be recycled to the reactor. The gas then flows to a shift converter where the ratio of CO to H_2 is adjusted through Reaction 5 to the proportions needed for methanation, i.e., three parts of H_2 to one of CO. This is done by passing the gas plus added steam over a catalyst bed, usually an iron-chromium oxide compound. The gas from the shift reactor contains the acid gases CO_2 and H_2S. They can be removed using one of the processes described previously for cleaning NG. The H_2S can be processed further to recover sulfur. Usually, NH_3 is removed by water scrubbing before acid gas treatment and can be recovered from the water.

Following cleanup, the gas is sent to the methanator where Reaction 4 is carried out over a nickel catalyst, at temperatures below 900°F to avoid catalyst deactivation. Such temperature control prevents the heat released from being used in the gasifier, but it can generate steam or be applied for other heating loads. The methanation step accomplishes two things. It converts a mixture of fuel gases of relatively low heating value into high-heating-value methane, and reduces the CO content to a level where the SNG is nontoxic.

Since water is formed during methanation, a drying step is required. After drying, a final fixed-bed methanation step, termed polishing, is necessary to remove the last small amount of CO in the methane-rich gas. The final SNG contains less than 10 ppm (volume) of CO.

The key step in the production of pipeline gas from coal is the gasification process. Generally, coal gasification systems are categorized according to the mechanical design of the primary gasifier as moving or descending bed, fluidized bed, and entrained flow. In addition, there is a small fourth classification, the molten salt or molten iron processes. Table C-5 indicates the large variety of gasifiers under development or commercially available in each of the major categories. Only a few representative processes are described briefly here.

C.2.1.1 Moving Bed Gasifiers

In this type of gasifier, sized coal is added at the top and the gasifying medium is injected at the bottom. Temperatures are generally lower than with other bed types. Owing to devolatilization at low temperatures, large amounts of heavy liquids (phenols, tars, etc.) are produced. High residence times are required, e.g., 1 hour for the Lurgi version. Ash is removed from the bottom as dry ash or slag. If slagging operation is conducted, the gasifier runs at comparatively high temperatures, uses more oxygen and less steam, and the reaction rate is faster. Output is therefore much higher than with the non-slagging operation mode. Inherent advantages of these gasifiers are high thermal efficiency and carbon conversion, as well as low contamination of gas with solids. One

disadvantage is that caking coal cannot be used without pretreatment. Also, the coal must have good mechanical strength and uniform size.

Table C-5. Summary of Coal Gasification Techniques (Ref. C-2)

TYPE	OPERATING PRESSURE	OXYGEN (O_2) OR AIR	AGGLOMERATION PREVENTION
DESCENDING BED			
DRY ASH, SINGLE STAGE			
GEGAS	TO 500 PSIG	AIR	STIRRER PADDLES
LURGI[1]	TO 450 PSIG	O_2 OR AIR	ROTATING BLADES
MERC	TO 105 PSIG	AIR	SPIRALING STIRRER
RILEY-MORGAN	40 IN. H_2O	AIR	AGITATOR IN ROTATING BED
WELLMAN-GALUSHA[1]	10 IN. H_2O	AIR	SPIRALING ARMS
WILPUTTE[1]	ATM	AIR	ROTATING ARM
DRY ASH, 2-STAGE			
ATC/WELLMAN (INCANDESCENT)[1]	ATM	AIR	NONE
FW/STOIC	ATM		NONE
RUHR-100	1,500 PSIG	O_2	STIRRER BLADES
WOODALL-DUCKHAM[1]	40 IN. H_2O	O_2 OR AIR	NONE
SLAGGING			
BGC/LURGI	TO 400 PSIG	O_2	STIRRER
GFERC	TO 400 PSIG	O_2	STIRRER
FLUIDIZED BED			
WINKLER[1]	ATM	O_2 OR AIR	
RHEINBRAUN	150 PSIG	O_2	
CO_2 ACCEPTOR	150 PSIG	AIR	
HYGAS	1,200 PSIG	O_2 OR AIR	
SYNTHANE	1,000 PSIG	O_2	
WESTINGHOUSE	225 PSIG	AIR	
U-GAS	350 PSIG	O_2 OR AIR	
COGAS	10 PSIG	AIR	
EDS (EXXON)	500 PSIG	NONE	
ENTRAINED FLOW			
SINGLE-STAGE			
BELL HPF	TO 225 PSIG	AIR	
KOPPERS-TOTZEK[1]	TO 12 PSIG	O_2 AND STEAM	
MOUNTAIN FUEL	TO 150 PSI	O_2 AND STEAM	
SHELL-KOPPERS	TO 450 PSI	O_2 OR AIR	
TEXACO	TO 1,200 PSIG	O_2 OR AIR	
TWO-STAGE			
BI-GAS	TO 1,500 PSIG	SYN GAS AND STEAM (STAGE 1) OXYGEN AND STEAM (STAGE 2)	
C-E	ATM	COMBUSTION GAS AND AIR (STAGE 1) AIR (STAGE 2)	
FOSTER WHEELER	ATM	SYN GAS AND STEAM (STAGE 1) AIR AND STEAM (STAGE 2)	
PEATGAS	TO 500 PSIG	SYNGAS (STAGE 1) O_2 AND STEAM (STAGE 2)	
ROCKWELL INTERNATIONAL	TO 1,500 PSIG	HYDROGEN (STAGE 1) NOT KNOWN (STAGE 2)	

(1) HAS BEEN USED COMMERCIALLY.

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The foremost example of this design is the Lurgi gasifier (Fig. C-15). The first such unit was built in Germany in 1936, and there now are at least 16 industrial plants using Lurgi gasifiers around the world. These are medium-pressure (375-400 psig), non-slagging units in which the ash is removed from the bottom without melting. The feed, usually subbituminous coal or lignite, is crushed to about 1/8 × 1-1/4 inches and can contain up to 35 percent moisture. The gasifier operates at temperatures from 1150 to 1400°F. A revolving grate supports the coal bed, cleans out the ash, and distributes the steam-oxygen mixture.

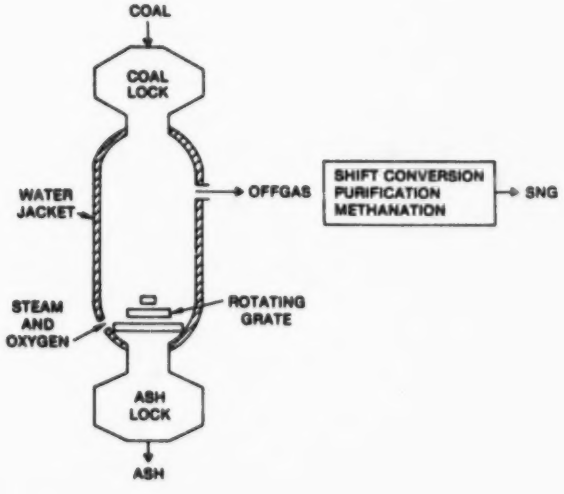

Figure C-15. Schematic Cross Section of a Lurgi Pressure Coal Gasifier (Ref. C-19)

A slagging gasifier version is being developed. Higher temperatures are used and the ash runs off as liquid slag. Higher efficiencies and increased output (by at least a factor of 3) are achieved when compared with a conventional dry ash unit (Ref. C-19).

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C.2.1.2 Fluidized Bed Gasifiers

A fluidized bed gasifier can operate with crushed or fine coal. The fluid bed allows complete gas-solid mixing and uniform temperature distribution. Fluidized beds can tolerate variations in coal feed during operation, have high gasification rates per unit cross-sectional area, and can operate over a wide load range without significant efficiency loss. They generally require pretreatment of caking coals, and have longer residence times than entrained beds. Operating temperatures are between those of moving and entrained bed designs. Exit gases have high dust loadings, and coal entrainment must be monitored frequently.

The only commercial gasifier in this category is the Winkler, developed in Germany but owned by Davy Powergas, Inc., since 1971. At one time there were 16 plants around the world using Winkler units, but only three are operating now. These gasifiers operate at 1500 to 1850°F under atmospheric pressure, although development of units operating at up to 15 atmospheres is under way (Ref. C-19).

As can be noted in Table C-5, there are a number of processes in the development stage that use fluidized beds. One of these is the HYGAS process, shown schematically in Figure C-16. Under development by the Institute of Gas Technology for more than 17 years, much of it with government funding, the feasibility of the process remains controversial.

Referring to Figure C-16, the heart of the process is the multi-bed vertical gasifier, consisting of three fluidized reaction beds and one fluidized dryer. Slurried, pulverized, pretreated coal is sprayed onto the dryer located at the top. The fluidizing medium in this dryer is product gas rising from the low-temperature reactor below. From the dryer, the gas stream goes to particulate scrubbing and methanation.

Overflow from the dryer falls to the bottom of the low-temperature reactor leg and is swept up to the first of two hydrogasification stages. This one operates at about 1200°F, with residence time of only a few seconds. The volatile matter in the coal and carbon are converted to methane by hydrogasification, and about 25 percent of the total

methane is formed here. The partially converted coal falls to the second or high-temperature bed, where it mixes with rising hydrogen-rich gas at about 1700°F. Part of the H_2 and steam react with the coal, forming about 25 percent of the total methane and carbon oxides. Hot residual char overflows to the bottom gasifier where it reacts with steam and O_2 at near 1850°F to form gases rich in H_2, and over 50 percent of the total methane.

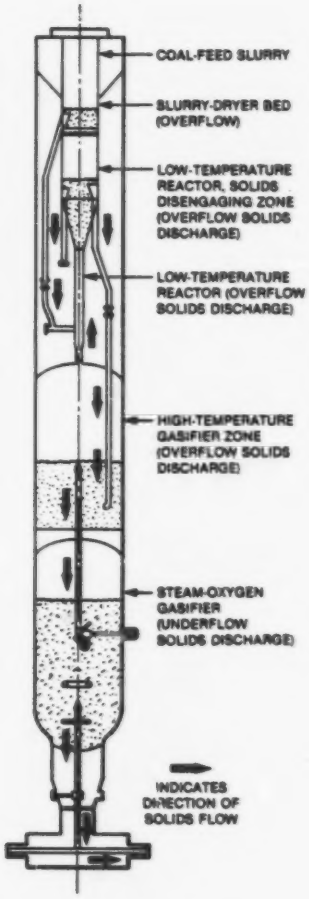
COAL-FEED SLURRY
SLURRY-DRYER BED (OVERFLOW)
LOW-TEMPERATURE REACTOR, SOLIDS DISENGAGING ZONE (OVERFLOW SOLIDS DISCHARGE)
LOW-TEMPERATURE REACTOR (OVERFLOW SOLIDS DISCHARGE)
HIGH-TEMPERATURE GASIFIER ZONE (OVERFLOW SOLIDS DISCHARGE)
STEAM-OXYGEN GASIFIER (UNDERFLOW SOLIDS DISCHARGE)
INDICATES DIRECTION OF SOLIDS FLOW

Figure C-16. Schematic Cross-Section of the HYGAS Main Reactor (Ref. C-20)

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The HYGAS system is more complex than other designs, but its efficiency is high and product cost is potentially one of the lowest. A large percentage of the potential methane is produced at about 1000 psi in the reactors, thus reducing the size of the methanation unit needed downstream.

C.2.1.3 Entrained Bed Gasifiers

In this type of gasifier, pulverized coal and gasifying medium are fed concurrently, and the coal is gasified in suspension. No pretreatment of caking coal is necessary, because the small coal particles are separated from one another in the flowing gas and are gasified so rapidly that agglomeration is impossible. The exit gas contains no tars or methane, because at the high temperatures of entrained bed gasifiers (3000°F) the main equilibrium gases are CO and H_2. To achieve the high temperatures, large amounts of O_2 are required relative to the other types of gasifiers. Gas production rates per unit volume of gasifier are also higher than in the other gasifiers because of the high temperatures and large particle surface area.

The foremost example of the entrained bed concept is the Koppers-Totzek (K-T) gasifier illustrated in Figure C-17. Coal from

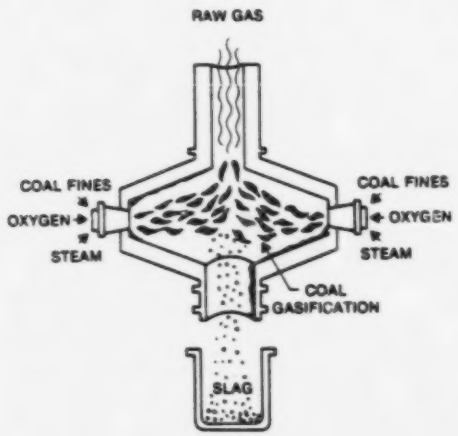

Figure C-17. Schematic Cross Section of the Koppers-Totzek Gasifier (Ref. C-19)

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stockpiles is dried and pulverized until 70 to 90 percent will pass through a 200-mesh screen. It is introduced through coaxial burners on all four sides. The gasifier is of double-wall construction (the annulus is used to raise steam), refractory lined, and operates at 3300°F and atmospheric pressure. Molten slag drops into a water quench tank, and represents about 50 percent of the coal ash. The remainder of the ash leaves the gasifier as fine particles entrained in the exit gas. Inasmuch as the gas consists primarily of CO and H_2, a heavy burden is placed on the shift and methanation reactors.

About 85 percent of the world's coal-based ammonia plants are using K-T gasifiers for H_2 production, in 16 plants in Europe, Asia and Africa. A high pressure (30 atmospheres) gasifier is under development. K-T units are being considered in the United States for coal plants producing ammonia or methanol. A Texaco design is nearing commercial status and has been selected for several early plants (Ref. C-21).

C.2.1.4 Underground Coal Gasification

In the discussion of coal gasification to this point, it has been tacitly assumed that the coal is mined by conventional underground or surface mining techniques and transported to a nearby chemical plant for gasification and conversion to SNG. An alternative approach is to gasify the coal in place, and bring only the product gas to the surface for cleanup and conversion. This method, termed underground coal gasification (UCG) or in situ gasification, has application to coal deposits whose recovery today is otherwise infeasible -- either technically or economically -- with conventional techniques. Generally, location of coal deposits at excessive depths is the justification for turning to UCG, but peculiarities of the coal deposits may also be involved. For example, over 100 billion tons of steeply-dipping-bed (SDB) formations -- coal seams lying at angles greater than 35 deg relative to the surface — are estimated to exist in the United States, mainly in the Pacific Coast area. In 1979, DOE-funded research proved the technical feasibility of UCG in these formations using slanting drill holes (Ref. C-22).

One key reason for UCG's development is its environmental advantages. Often-cited pluses are (1) health and safety problems are minimized since no mining is required, (2) less atmospheric pollution and surface disruption than with strip mining, and (3) less solid waste brought to the surface than in conventional underground mining. On the other hand, there are everal potential problems that include (1) contamination of surface water and underground aquifers, (2) subsidence, and (3) pock-marked landscape left by the one hundred or more pairs of injection and production holes necessary for each commercial-scale facility.

There is considerable disagreement regarding the economics of UCG. According to Lawrence Livermore Laboratory, UCG is roughly 30 percent less costly than conventional gasification, but a spokesman for Arthur D. Little, Inc., contends that neither United States nor Soviet technology looks economical compared with aboveground gasification (Ref. C-22).

Original work on UCG focused on air injection, thereby producing a low-Btu gas unsuitable for SNG applications. In fact, gas heating values have been even lower than expected, running nearer to 95 Btu/scf than the expected 126 Btu/scf. However, recent pilot runs in the United States with steam-oxygen injection produced a nitrogen-free gas with a heating value of 250 to 300 Btu/scf suitable for upgrading to SNG or synthesis to methanol (Ref. C-22).

One of the methods that has been investigated for UCG is termed the Linked Vertical Well (LVW) process, and was used in Reference C-23 as a basis for design and economic evaluations for SNG production. The technique is carried out in five stages as illustrated in Figure C-18. In Stage 1, the natural permeability of the coal is enhanced by creating and enlarging paths in the coal seam between the linking well and production well. This may be done by means of high-pressure air injection, alternating high-and low-pressure air, and hydraulic fracturing followed by air injection.

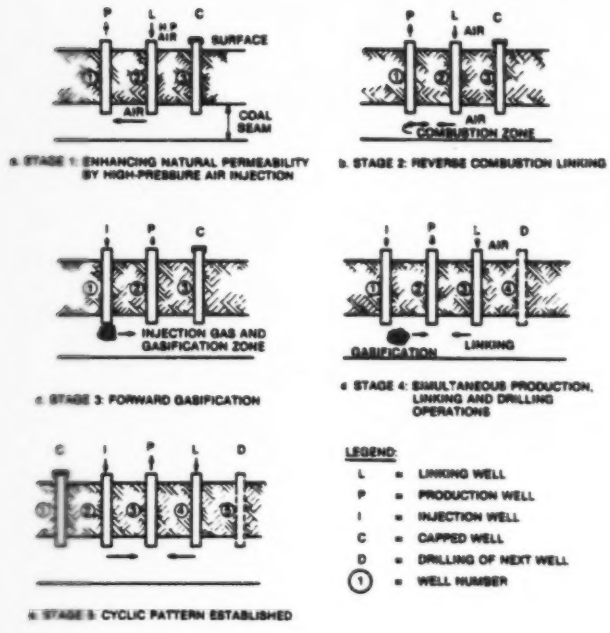

Figure C-18. Schematic Representation of the Stages in Field Development of the Linked Vertical Well Process (Ref. C-23)

The second stage is the reverse combustion linkage step, whose purpose is to accomplish linkage of the wells. A fire is started in the production well and air (or steam-oxygen) is injected into the linking well. The combustion front moves toward the linking well, advancing in the direction opposite to that of the gas flow. Completion of the reverse combustion link is indicated by an abrupt drop in the linking gas injection pressure.

Once linkage of the boreholes is completed, the third stage can begin. The initial production well (well 1) is converted to an injection well and the original linking well (well 2) is changed to a production well. The gasification zone at the bottom of the injection well enlarges and proceeds along the passage or channel formed during the reverse linking step, that is, the zone moves in the same direction as the flow of injection and product gases (forward gasification). As gasification pro-

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ceeds, the channel widens and caves in, exposing more coal to be gasified. In the fourth stage, the next adjacent well (well 3) is linked to well 2. This could also be done simultaneously with Stage 3. Drilling operations for the next well in the system are also performed during Stage 4.

The fifth stage takes place after gasification of the coal between the first two wells is completed. The first well is capped and the second well becomes the injection well, while the third well now becomes the production well. The fourth well becomes the linking well, the fifth is drilled and a cyclic pattern is established which is repeated for successive wells.

This description of the LVW process applies to a single line of wells. In practice, a number of parallel lines of wells can be operated simultaneously to exploit large-area coal seams. For a design throughput of 150 million scf of SNG per day, 60 producing wells must be on-line. These 60 wells would generally be arranged in six parallel trains of 10 wells each. Each train also requires 10 injection wells and 10 linking wells, so that a train consists of a total of 30 wells. Once the gas is brought to the surface, it can be processed in the same manner as a conventionally gasified product, viz., cleaned, compressed, fed to the shift reactor, CO_2 and H_2S removed, and methanated.

Among the problems that need further R&D effort are (1) control of the gasification reactions to obtain high quality gas, (2) establishment and maintenance of coal permeability, (3) leakage and subsidence control, (4) prevention of groundwater intrusion, (5) long-term testing (at least 1 year), and (6) demonstration of economic competitiveness based on test data. It is doubtful that UCG will make a significant contribution to United States gas supplies before the 1990s.

C.2.1.5 Energy Efficiency

The energy efficiencies associated with the various steps in converting western surface-mined coal to high-Btu SNG are shown in Table C-6. The reader is referred to Subsection C.1.6 for general background material, assumptions, and limitations of the energy data presentation.

Table C-6. Production Efficiencies for SNG from Coal[1]

PRODUCTION STEP	STEP EFFICIENCY CNG	LNG
SURFACE MINING	0.986	0.986
COAL PROCESSING	0.95	0.95
COAL CONVERSION	0.65	0.65
PIPELINE TRANSPORT	0.95	0.95
GAS STORAGE[2]	0.996	NA
GAS DISTRIBUTION	0.993	NA
LIQUEFACTION	NA	0.86

(1) TYPICAL OF WESTERN COAL CONVERSION AT MINEMOUTH.
(2) UNDERGROUND OR GAS HOLDERS.

Efficiencies for the first four process steps in the table are identical for CNG and LNG. Values for surface mining and coal processing are taken from Reference C-6. Conversion includes gasification and the necessary processing to produce a high-Btu pipeline gas. Inasmuch as conversion efficiency is dependent on the specific process, type of coal, and utilization of by-products, it is difficult to define a single value for it. However, a value of 65 percent is reported in References C-24, C-25 and C-26 and is used in the energy analysis of Reference C-27. Other values in the literature fall within the bounds of 65 ± 3 percent. The remaining step efficiencies and their rationale in Table C-6 follow those in Table C-4, and the discussion for the latter should be consulted for details.

C.2.2 Biomass Gasification

The biomass resource refers to growing plant life, either terrestrial or aquatic, with the former subdivided into wood and crop materials. Inasmuch as interest here is on SNG production, fermentation of biomass to ethanol or butanol is excluded from the review.

There are two general approaches for converting biomass to methane: thermal gasification and anaerobic digestion. Each method has inherent advantages and limitations. For example, anaerobic digester design and operation are simple and inexpensive, and can take place at relatively low temperatures and pressures with either wet or dry feeds. However, anaerobic digestion suffers from low conversion efficiencies and low gas production rates, and requires a balance of nutrients in the feed. In contrast, thermal gasification processes have high conversion efficiencies and conversion rates but require a feed with a low moisture content and entail complex, high-temperature and, often, high-pressure operations.

Table C-7 shows a comparison of anaerobic digestion and thermal gasification for the conversion of organic matter to SNG. The anaerobic process converts about 50 percent of the organic matter to a product gas containing methane and CO_2 in a volume ratio of 60:40. Thermal gasifica-

Table C-7. Comparison of Anaerobic Digestion and Thermal Gasification for Conversion of Organic Matter to SNG (Ref. C-28)

PARAMETER	ANAEROBIC DIGESTION	THERMAL GASIFICATION
LOADING, LB ORGANIC/FT^3-DAY	0.1	3070(1)
RETENTION TIME	10-20 DAYS	10-20 MINUTES
OUTPUT, 10^3 BTU/FT^3-DAY	0.3-4.0	14,440(1)
REACTOR TEMPERATURE, ^0C	35,55	350-550
THERMAL EFFICIENCY, %	40	60
ORGANIC RESIDUES, % OF FEED	50	<5
FEED WATER REQUIREMENTS, %	>20	<50
FEED NUTRIENT REQUIREMENT	BALANCE OF C, N, AND P	NONE
PRODUCT GAS	CH_4, CO_2	CH_4, CO, H_2, CO_2 HYDROCARBONS

(1) THERMAL GASIFIER ONLY

tion almost completely converts the organic matter to a mixed gas stream which may contain small quantities of undesirable hydrocarbons. The choice of process depends to a large extent on the nature of the feedstock to be processed. For aquatic biomass such as kelp and water hyacinth, with moisture contents of 88 and 95 percent, respectively, anaerobic digestion is the only feasible choice; complete moisture removal prior to or during thermal gasification would use almost twice as much energy as contained in the feedstock. Anaerobic digestion is also a more efficient process for some grasses which have moisture levels in the 50 to 60 percent range. Conversely, thermal conversion is probably the process of choice for most woody materials, since these feedstocks are relatively low in moisture and contain ligno-cellulosic complexes which are readily converted thermally but are resistant to bacterial breakdown (Ref. C-28).

The following two subsections briefly review the current technology status of anaerobic digestion and thermal gasification. The material also serves as a basis for later discussions of municipal solid waste (MSW) gasification.

C.2.2.1 Anaerobic Digestion

Anaerobic digestion involves three successive fermentation stages performed by a mixed culture of microorganisms with specific substrate requirements. The first stage is the hydrolysis of large organic molecules (e.g., cellulose and other carbohydrates, fats and proteins) into lower molecular weight sugars, fatty acids, and amino acids. In the second stage, these products are converted to volatile fatty acids, lower alcohols, aldehydes, CO_2, H_2 and H_2S. The third stage is the synthesis of methane from the volatile acids. Additional CO_2 and trace gases are also generated. Most anaerobic digestion descriptions combine the first two stages into one phase because they are performed by the same type of acid-forming bacteria (acidogens). The second phase is then effected by methane-forming bacteria (methanogens). The process is depicted in Figure C-19.

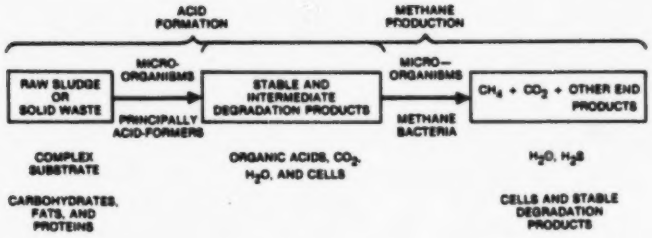

Figure C-19. Block Diagram of the Anaerobic Digestion Process (Ref. C-29)

Acidogens can exist over a wide range of environmental conditions, while methanogens are sensitive to such environmental factors as acidity, feed concentration, and temperature. Because of this sensitivity and their slow growth rate, methanogens are the digestion rate controllers. Digestion proceeds most efficiently when these two populations are in equilibrium, i.e., when the volatile acid synthesis rate equals the methane synthesis rate. The result is a medium with a near-neutral pH.

Gas production can occur within two distinct temperature ranges: (1) mesophilic, below 45°C and generally near 35°C, and (2) thermophilic, above 45°C and usually near 55°C. The latter alternative is of interest because it generally allows higher feed loadings and shorter retention times. However, it also has the disadvantages of higher energy requirements and poorer process stability. Research on kelp digestion has shown that, for reasons presently not understood, this feedstock produces less methane at the higher temperature. Moreover, due to the 88 percent moisture content of kelp, it takes about 50 percent of the kelp energy to raise the feed to thermophilic temperatures (Ref. C-28).

Several current and advanced digester designs are shown schematically in Figure C-20. In a conventional digester, mixing may be accomplished by internal propellers or external pump circulation. Mixing is beneficial because it eliminates layering, equalizes operating conditions, and allows the bacteria to thoroughly contact the organic feed material.

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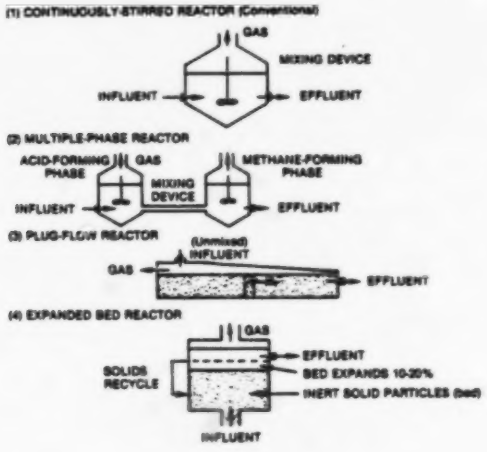

Figure C-20. Examples of Anaerobic Digester Designs (Ref. C-28)

One problem is that acidogens and methanogens require different conditions for optimum growth, and these conditions cannot be easily achieved in a single digester. As a result, the methanogens exhibit slow growth, and a large percentage are lost with the effluent. One approach to prevent cell washout is to subject the effluent to anaerobic settling and recycle a portion of the sediment containing viable bacteria back to the digester.

Another technique, which has not been applied as yet to a full-scale plant, is to optimize conditions for each type of bacteria by using two reactors. The plug-flow reactor also addresses this problem. In this design, an axially uniform fluid segment flows through an elongated reactor with minimal longitudinal mixing. In this way, the acid-formers can proliferate at the influent end, while the methane-formers can reside in large numbers at the effluent end. Preventing longitudinal mixing is a problem in plug-flow designs.

A third design that has recently received much research effort is the fixed-film digester, one version of which is the expanded-bed reactor shown in Figure C-20. The methanogenic bacteria are attached to

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inert solid particles which have a much longer retention time in the system than the liquid phase. The expanded bed is an improvement over packed bed systems for particulate feeds, since fluidization by the flowing feed prevents clogging by feed particles. Laboratory data on cattle waste feed have indicated that hydraulic retention times can be reduced by at least an order of magnitude. However, this concept has not yet been well evaluated for biomass feedstocks (Ref. C-28).

Finally, the Institute of Gas Technology has combined anaerobic digestion and thermal gasification in its BIOTHERMGAS process. In this process, anaerobic digestion, sludge dewatering, steam-oxygen gasification, and catalytic methanation (or biomethanation) of the hydrogen-rich gas from the thermal gasifier are combined in that order to produce methane. The refractory organics from the digester are thus completely gasified and waste heat as well as ammonia and inorganic nutrients can be recycled from the thermal gasifier to the digesters (Ref. C-30).

There are no commercial anaerobic digestion plants using biomass as a feedstock. Inasmuch as this technology is still at an early stage of development, and current anaerobic digestion facilities generally operate at low efficiencies, this process for generating methane from biomass has not been considered a viable supply source for vehicle use and has not been included in the energy evaluation. However, thermal gasification of wood, although at an early point in development, shows more near-term potential. It is discussed in the following subsection.

C.2.2.2 Thermal Gasification

Wood gasification for the production of low-Btu gas is not a new concept, and some gasifiers of this type are commercially available today in the United States. However, such units are generally air-blown and of small size, e.g., 10 to 20 million Btu/day, equivalent to 15 to 35 dry tons per day of feed (Ref. C-31). If interest is confined to the manufacture of SNG or synthesis gas for methanol production, technology is at the R&D stage with ongoing investigations from the laboratory level to the pilot scale.

Compared to the gasification of high-sulfur eastern bituminous coal, wood[3] should (1) exhibit greater reactivity with higher carbon conversion, (2) produce a product gas with a larger proportion of CO_2 (because of the oxygen in the wood), (3) produce very little H_2S, and (4) probably produce an ash-char mixture of lower bulk density. These and numerous other factors affect gasifier design, which is presently far from the optimization stage. Reactors under investigation include coal-related configurations such as moving beds, fluidized beds, entrained-feed gasifiers plus rotating kilns, single- and multiple-hearth reactors, and other designs. Questions being studied include feed size requirements, effect of low ash content, and flow characteristics of biomass particles. Much of the current research emphasizes gasification in fluidized bed systems, and new reports have appeared which indicate that recently obtained information could lead to superior processes (Ref. C-30). Several approaches are described below.

Catalytic steam gasification in fluidized beds at atmospheric pressure has been reported to be effective for producing product gases useful for either SNG or methanol production. The advantages of catalytic steam gasification are that (1) no oxygen is required, (2) little or no tar is formed, (3) no shift reactor is required for methanol synthesis, (4) methanation requirements are low, and (5) yields and efficiencies are greater than those obtained by conventional gasification. Capital costs for a commercial plant are therefore expected to be significantly reduced.

Catalysts which are effective have a nickel concentration of at least 25 percent, an acidic support such as silica-alumina, and a surface area of greater than 100 square meters per gram. Based on data obtained from operation of a process development unit (PDU), a plant design study was performed to permit estimates of process economics (Ref. C-32). Table C-8 indicates conditions required to produce either methane or methanol

[3] Comments here relative to wood also apply to such related materials as corncobs, corn stover, and wheat straw.

Table C-8. Wood Conversion Plant Design Bases (Ref. C-32)

	WOOD TO METHANE	WOOD TO METHANOL
CAPACITY, DRY TONS WOOD/DAY	2000	2000
LOCATION	PACIFIC NORTHWEST	PACIFIC NORTHWEST
PRODUCTION SPECIFICATIONS	21.6 M SCF/DAY HHV - 956 BTU/SCF 0.1 VOL % CO 3 VOL % CO_2 H_2S - 0.25 GR/100 SCF WATER - 7 LB/10^6 SCF	METHANOL 99.3% PURITY 3.03×10^5 GAL/DAY
GASIFIER CONDITIONS		
TEMPERATURE, °C	550	750
PRESSURE, ATM	10	10
STEAM RATE, WT/WT DRY WOOD	0.33	0.75
CHAR PRODUCTION, WT/WT MAF WOOD	0.24	0.15
CHAR HEATING VALUE, BTU/LB	13,500	14,000
GAS PRODUCTION, WT/WT MAF WOOD	1.09	1.60
COLD GAS EFFICIENCY, %	65	88
GAS COMPOSITION, VOLUME %		
H_2O	38.0	28.7
H_2	11.2	36.6
CH_4	23.6	4.0
CO_2	19.5	12.4
CO	7.7	18.3

from wood. Note that gasification for methane production is at a lower temperature than in the case of synthesis gas for methanol. Figure C-21 shows the plant flowsheet for methane production. Char and catalyst are collected from the gasifier and exit gas, each source contributing about equal amounts of catalyst. The ratio of char to catalyst is about 50:1 by weight. The catalyst can be separated from the char magnetically, with recovery assumed to be about 95 percent. The catalyst can be regenerated by passing steam at 650°C over it, then reducing it with the product gas (Ref. C-32).

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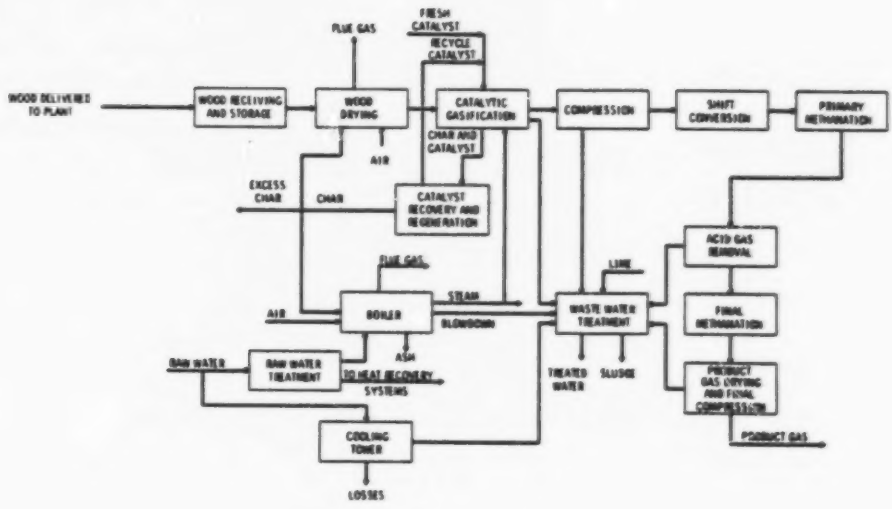

Figure C-21. Block Diagram of the Wood-To-Methane Process (Ref. C-32)

Noncatalytic fluidized bed gasification is also being developed at temperatures near 800°C, but at pressures of about 300 psi. The residence time in the reactor is estimated to be 3 to 5 minutes to achieve 95 percent carbon conversion. For biomass containing 30 percent moisture, calculations indicate that external steam addition may not be necessary, and that about one-half of the total methane would be produced directly in the gasifier (Ref. C-30).

C.2.2.3 Energy Efficiency

The energy efficiencies associated with the various steps in converting wood to high-Btu SNG are shown in Table C-9. The reader is referred to Subsection C.1.6 for general background material, assumptions, and limitations of the energy data presentation.

Efficiencies for the first four process steps in the table are identical for CNG and LNG. Values for wood harvesting and local (50 miles) transport are taken from Reference C-33. There are few estimates of conversion efficiency in the literature. The value in Reference C-31

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Table C-9. Production Efficiencies for SNG from Wood

PRODUCTION STEP	STEP EFFICIENCY CNG	LNG
HARVESTING	0.978	0.978
LOCAL TRANSPORT	0.979	0.979
WOOD CONVERSION(1)	0.60	0.60
PIPELINE TRANSPORT	0.95	0.95
GAS STORAGE(2)	0.996	NA
GAS DISTRIBUTION	0.993	NA
LIQUEFACTION	NA	0.86

(1) ASSUMES CONVERSION BY THERMAL GASIFICATION
(2) UNDERGROUND OR GAS HOLDERS

is 63 percent, and 58.3 percent in Reference C-32; an approximate average value of 60 percent was selected. The remaining step efficiencies in the table apply to all of the gas systems.

C.2.3 Waste Gasification

Waste resources include urban refuse in the form of MSW, industrial waste, sewage and animal manures. Sewage has been gasified for many years by anaerobic digestion, primarily for public health and, more recently, environmental reasons. The generated methane was considered a worthless by-product for many years and generally was flared. Animal manures have been gasified on a local basis in the less-developed countries for heat and light, but large-scale gasification in the United States was only initiated in the 1970s and is still in the demonstration stage. MSW represents another renewable energy source currently undergoing rising interest for energy and possible resource recovery. Current projects seem to be primarily aimed at direct combustion of raw MSW, with minimal or no front-end recovery. However, the recovery of methane from MSW in landfills is growing, and a demonstration MSW-sewage sludge project has been under way for several years. MSW thermal gasification projects have thus far aimed at low- or medium-Btu gas production rather than SNG or methanol.

The following material briefly reviews gasification methods for these waste materials. Inasmuch as the basic anaerobic digestion and thermal gasification technology has already been addressed, only differences in application are covered here.

C.2.3.1 Anaerobic Digestion

Research on the development of anaerobic digestion for wastes has been conducted with evaluation of different feedstocks and development of advanced digesters and system designs. Municipal, industrial, and animal waste materials are being evaluated alone and in mixtures. The energy, moisture, volatile solids, and ash values are often quite different between the various feedstocks, but when balanced digestion is attained, the gas production parameters, volatile solids reductions, and energy recovery efficiencies appear to span a relatively narrow range if digestion conditions are similar (Ref. C-30).

Commercial methane recovery is growing at a modest rate for landfill MSW and manure via anaerobic digestion, but no digestion plants supplied with MSW or MSW-sewage sludge blends have been commercialized. The largest demonstration plant is the proof-of-concept, 100 ton/day plant sponsored by DOE in Pompano Beach, Florida. The plant flowsheet is shown in Figure C-22. Shredded solid wastes are fed to the system from an adjacent shredding facility on an as-needed basis, after magnetic removal of ferrous metals. Wastes are placed in a storage building until required. The wastes are then screened to remove fines and shredded again to a smaller size before being sent through an air classifier and separator to remove heavy fractions such as glass and aluminum. Entering a mixing tank, the remaining refuse is combined with sewage sludge, nutrients, water, and steam (for temperature control) before being put into one of two digesters. The digester tanks are continuously stirred and the wastes remain there for 5 to 30 days, depending on the testing period. From 91 metric tons (100 tons) per day of solid waste fed into the plant, 10,670 cubic meters (376,800 scf) of gas are generated, containing 50 percent

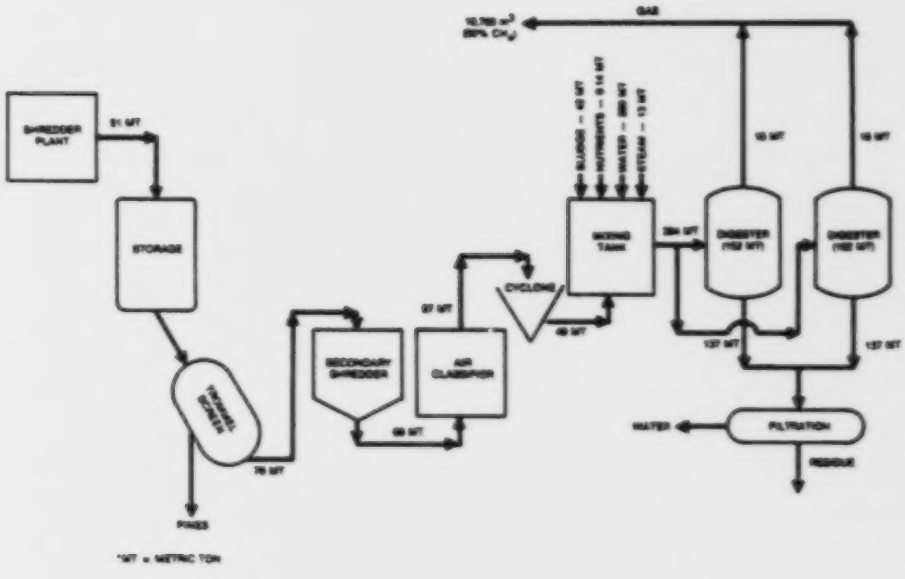

Figure C-22. Flow Diagram for the Integrated Refuse Utilization System (Ref. C-29)

methane. The plant is operating in a testing mode to determine the effects of variations in temperature, pH, detention time, nutrients, solids concentrations, and feed rates (Ref. C-29).

The product gas can be upgraded to pipeline quality by the processing steps outlined in Subsection C.1.3. In particular, an ethanolamine or diglycol-amine solution can be used to absorb the CO_2 and H_2S impurities. Alternatively, molecular sieve beds can adsorb these materials and also dry the gas. A patented water-scrubbing process, termed Binax, has been applied to sewage gas in Modesto, California, to produce CNG for vehicle use. The pilot plant started operation in October 1978, and has a maximum capacity of 20,000 to 40,000 scf of digester gas per day. The process is shown in Figure C-23. The digester gas is compressed and scrubbed with water to remove the CO_2 and H_2S; then the water is regenerated and the impurities are released to the atmosphere. If required

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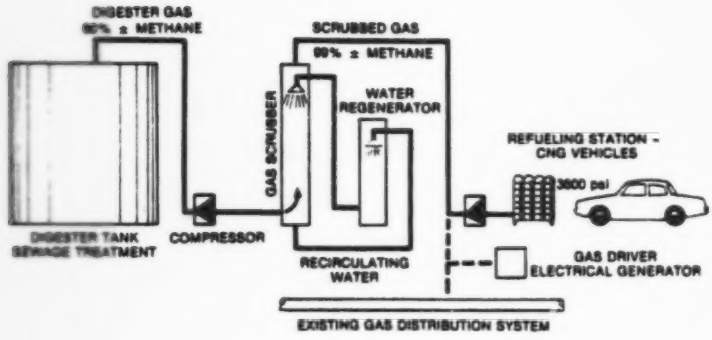

Figure C-23. Schematic Representation of the Dual Fuel Systems Sewage Gas Vehicle Fueling System (Ref. C-34)

for a commercial system, the H_2S could be recovered and the gas dried for injection into an NG pipeline. The pilot unit captures over 90 percent of the methane, and produces a gas that is over 98 percent pure methane with a heating value of about 1000 Btu/scf (Ref. C-34). It should be noted that many sewage treatment plants utilize digester gas for plant power and heat. Excess gas is often sold as-is to nearby electric power plants.

Another variation of anaerobic digestion of MSW is in sanitary landfills. Historically, one of the most troublesome environmental impacts associated with disposal of MSW in such landfills has been the generation of landfill gas (methane and CO_2). If not properly controlled, this landfill gas can migrate through the soil and adversely affect groundwater quality, or accumulate in nearby buildings creating an explosion and/or fire hazard. In the last few years, in an attempt to control the gas migration problem, and recognizing its economic potential as a fuel, several sanitary landfills have established programs to recover methane. A list of such landfills is given in Table C-10. Note that only four are designed to produce a high-Btu gas, although there is no technical reason for the low percentage.

At Mountain View, California, a similar methane recovery program is in operation with a different end use for the fuel. The Mountain View

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Table C-10. Landfills Currently Used for Commercial Methane Recovery[1] (Ref. C-30)

LOCATION	WELL TYPE[4]	PRODUCT[5]	PRODUCTION[5] MMCF/DAY	SYSTEM COST 10^6	START DATE	OPERATOR	GAS USE
AZUSA, CA[2]	D	MBG	0.75	1.2	1978	AZUSA LAND RECLAMATION CO.	SOLD TO REICHOLD CHEMICAL CO.
CINNAMINSON, NJ[2]	-	MBG	0.3	-	1979	PUBLIC SERVICE ELECTRIC & GAS CO.	INDUSTRIAL SALES
INDUSTRY, CA[2]	S	MBG	0.7	0.4	1978	SCS ENGINEERS	BOILER FUEL
LOS ANGELES, CA[2] (SHELDON ARLETA)	D	MBG	2.6	1.75	1979	CITY	CITY ELECTRIC POWER
MONTEREY PARK, CA[2]	D	SNG	4	-	1979	GETTY SYNTHETIC FUELS INC.	SOLD TO SOUTHERN CALIF GAS CO.
MOUNTAIN VIEW, CA[2]	S	MBG	0.7	0.84	1978	PACIFIC GAS & ELECTRIC CO.	BLENDED INTO NATURAL GAS
PALOS VERDES, CA[2]	D	SNG	0.75	-	1975	GETTY SYNTHETIC INC.	SOLD TO SOUTHERN CALIF GAS CO.
WILMINGTON, CA[2] (ASCON)	S	MBG	1.5	-	1978	MATSON ENERGY SYSTEMS	SOLD TO SHELL OIL REFINERY
CARSON, CA[3]	S	MBG	0.6	-	LATE 1980	SYULY ENTERPRISES	ENGINE FUEL FOR ELECTRIC POWER
CHICAGO, IL[3]	-	SNG	2.3	-	LATE 1980	GETTY SYNTHETIC FUELS INC.	SOLD TO NATURAL GAS PIPELINE CO. OF AMERICA.
GLENDALE, CA[3] (SCHOLL CANYON)	D	MBG	1.2	-	JUNE 1981	CITY	ENGINE FUEL FOR ELECTRIC POWER
LOS ANGELES, CA[3] (PUENTE HILLS)	D	MBG	-	-	EARLY 1981	LOS ANGELES COUNTY SANITARY DISTRICT	BOILER FUEL FOR HEATING AND COOLING
LOS ANGELES, CA[3] (BRADLEY EAST)	D	MBG	2.0	-	LATE 1980	COMROCK CO.	SOLD TO CITY FOR ELECTRIC POWER
LOS ANGELES, CA[3] (LOPEZ CANYON)	D	MBG	0.1	-	EARLY 1981	CITY	ENGINE FUEL FOR ELECTRIC POWER
MARTINEZ, CA[3] (ACME)	-	MBG	-	-	LATE 1980	GETTY SYNTHETIC FUELS, INC.	BOILER FUEL FOR ELECTRIC POWER
ORANGE COUNTY, CA[3] (COYOTE CANYON)	-	-	-	-	LATE 1980	IRVINE CO.	TESTING
SAN LEANDRO, CA[3] (DAVIS STREET)	-	MBG	-	-	LATE 1980	GETTY SYNTHETIC FUELS, INC.	BOILER FUEL FOR ELECTRIC POWER
STATEN ISLAND, NY[3] (FRESHKILLS)	S	SNG	-	-	MARCH 1982	GETTY SYNTHETIC FUELS, INC.	SOLD TO BROOKLYN UNION GAS CO.
STATEN ISLAND, NY[3]	S	MBG	0.07	-	JULY 1980	BROOKLYN UNION GAS CO.	ENGINE FUEL FOR ELECTRICITY

(1) SOURCE: U.S. ENVIRONMENTAL PROTECTION AGENCY. GETTY SYNTHETIC FUELS INC.
(2) OPERATIONAL.
(3) PLANNED.
(4) S, SHALLOW, LESS THAN 100 FT; D, DEEP, MORE THAN 100 FT.
(5) MBG, MEDIUM-BTU GAS; SNG, HIGH-BTU GAS.

sanitary landfill, part of the development of a large regional park, is disposing of solid wastes from the city of San Francisco, as well as its own solid wastes. Under a royalty agreement with the city of Mountain View, the Pacific Gas and Electric Company (PG&E) is recovering landfill gas from 33 wells within a 30 acre section of the landfill. Approximately

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1,200,000 scf of landfill gas are being recovered daily, at a methane concentration of 45 to 50 percent. The landfill gas is cleaned (using a molecular sieve) and compressed to pipeline quality standards before it is injected into a PG&E NG pipeline that crosses the site. Cleanup of the gas removes the CO_2 and other impurities, reducing the volume of gas by about 50 percent while at the same time doubling the energy content. The volume of gas injected into the pipeline averages 600,000 scf per day at a methane concentration of approximately 95 percent (Ref. C-29).

Although the degradation process for landfills is essentially the same as that for sewage sludge, control of temperature, moisture, and homogeneity of waste material is more difficult to obtain for landfills. Because of the growing interest in methane recovery from landfills, research is being conducted on manipulating certain variables of landfilling to increase methane yield in shorter periods. This can include sewage sludge addition, different moisture content, and surface sealing.

Gas production in landfills depends on decomposable solid waste and biological organisms to effect the decomposition. These organisms, in turn, have certain environmental requirements that must be satisfied. The two factors most affecting methane production are moisture content and temperature. A moisture content of 34 to 50 percent by weight is necessary for active methane generation. Optimal temperatures are within the 86 to 104°F range. Although methane production is routinely found in all decomposing landfills, suboptimal moisture and temperature conditions can severely retard its generation.

As a landfill is filled, some time elapses before methane production begins. The production rate gradually increases, and after several years begins to decline. In the later years stable methane generation is most susceptible to upset. Consequently, predictions of methane generation rates are equivocal. The theoretical amount of gas generated from typical residential-commercial-light industrial solid waste is 7.2 scf per pound of wet (as received) waste. Methane generation has been estimated by the Environmental Protection Agency (EPA) to be about 0.13

scf per pound of refuse per year after 5 years in a landfill. Although maximum methane generation is supposed to occur in these first 5 years, many researchers believe that landfills remain economically productive from 15 to 25 years.

Gas recovery from landfills must also be carefully monitored. Usually, landfill gas with the highest methane content (50 to 70 percent) is generated near the center of the landfill. Gas at the landfill perimeter is normally not considered an economical supply, due to its lower methane content (20 to 35 percent). Because a vacuum is applied to collect the gas, engineering designs must stipulate the maximum allowable applied vacuum before air is forced into the landfill. Not only does the air dilute the methane recovered, it also destroys the anaerobic environment. Consequently, methane generation is reduced and a lag period must elapse before anaerobiosis is restored (Ref. C-29).

The last application of anaerobic digestion to be addressed is the gasification of animal manures. Collection of animal manures for processing into gas is economically limited to operations where substantial numbers of animals are confined to a relatively small area. Only cattle in feedlots generate sufficient manure to warrant selling the methane to a pipeline, although smaller quantities can be used on-site. Alternative economic uses, such as fertilizer, also limit potential gas production (Ref. C-2).

Commercial manure gasification projects utilizing anaerobic digestion are being built at both small and moderate scales. Examples are the farm-scale plug-flow system in Gettysburg, Pennsylvania, and a Lamar, Colorado, plant that will be sized to digest 340 tons/day of manure from 50,000 head of cattle and produce about 1 mmscf/day of methane. Innovative features of the plug-flow system include a plastic cover, which serves both to maintain anaerobic conditions and collect the gas, and the use of a special diesel engine-generator set. The engine uses a small amount of pilot diesel fuel (15 percent) to ignite the gas. The 2,675-acre farm produces all of its own power with this system, as well as a

surplus which is sold to the local power company. The Lamar, Colorado, plant has not been placed on-line yet; start-up is scheduled for 1982 (Ref. C-30).

Unfortunately, the country's first large-scale manure gasification plant, which was designed to supply about 2 mmscf/day of SNG in Guyman, Oklahoma, to the Natural Gas Pipeline Company, will not manufacture SNG in its future operations. Only cattle feed and liquid fertilizer will be made, because the operator, Calorific Recovery Anaerobic Processes, Inc., has not been able to produce SNG at a competitive price. This is not unexpected, because various economic analyses of cattle manure gasification by anaerobic digestion indicate that the digested solids for cattle feed are a very important product. In many cases, methane might even be considered to be a by-product. Capital and operating costs for a 120,000 scf/day SNG plant have been estimated. Without any credit for the residual solids as an animal feed, the methane cost, excluding feed or feed transportation costs, was projected to be $9.33 per mmBtu. If credit is taken for the residuals, methane cost was reduced to $5.15 per mmBtu. Development of suitable technology for recovering the digested solids in manure-to-methane plants, and determination of their actual feed value, thus seems mandatory if large-scale commercial plants are to compete. This work is in progress at several locations (Ref. C-30).

C.2.3.2 Thermal Gasification

Although some research work has been performed on fluidized bed gasification of manure particles (Ref. C-30), the commercial potential of this resource compared to MSW is so much smaller that only the latter will be considered further in this discussion. While high-Btu gas is a possible product of MSW from a technical standpoint, it is much more economical to produce the same energy in the form of low- or medium-Btu gas. This can be sold in the local industrial area adjoining the plant for general heating or boiler use, or mixed with local NG. An alternative is direct combustion of the organic material, thereby avoiding the heavy investment in a gasification plant.

Many of the MSW plants that were built during the 1970s were plagued with operating difficulties caused by poor design, excessive wear, corrosion, and failure of some units, particularly front-end equipment for resource recovery. More development work is apparently necessary to perfect front-end designs for large-scale plants. The few small- to moderate-scale plant designs that have shown satisfactory performance cannot be easily extrapolated to large plants. The current trend, therefore, is to combust the raw MSW, with minimal or no front-end processing for resource recovery and recycling (Ref. C-30).

The only MSW process that currently has the potential of producing SNG is the Union Carbide PUROX system, which is designed at present to make only a medium-Btu gas. A modular demonstration plant was operated successfully in Charleston, West Virginia, and two 100 ton/day commercial plants have been built in Japan (Ref. C-30). A process flowsheet is shown in Figure C-24. It incorporates a slagging, vertical-shaft furnace using

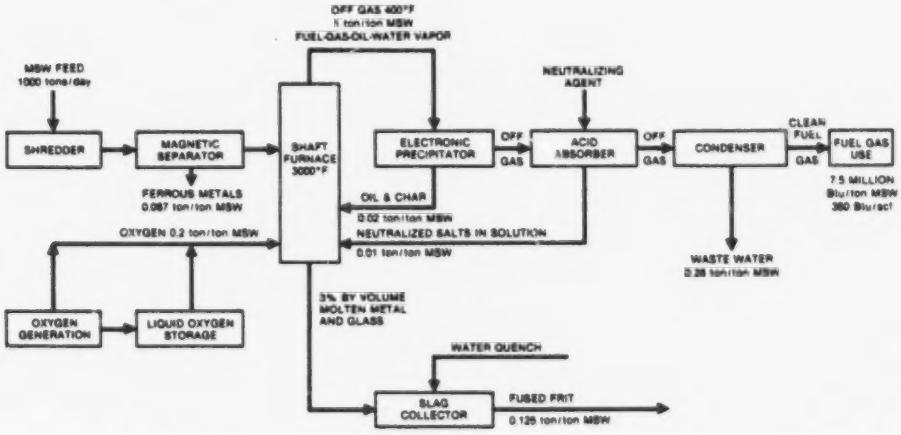

Figure C-24. Block Diagram of the Union Carbide PUROX System (Ref. C-18)

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oxygen instead of air, and is compatible with any front-end separation system. In the process shown, only the iron is removed (magnetically), whereas glass and other metals pass through the furnace and end up as a salable fused frit.

The shaft furnace runs at slagging temperatures near 3000°F and at atmospheric pressure. Each furnace has a gas cleanup train consisting of a water spray, an electrostatic precipitator, an absorber, and a condenser. Oxygen is supplied by a cryogenic air separation unit. Slag is tapped continuously by allowing it to overflow into a water quench tank. Analysis of the product gas is shown in Table C-11. Its heating value ranges between 350 and 370 Btu/scf (Ref. C-18). To produce SNG, this gas must be shifted and methanated as previously described.

Despite the PUROX plants in Japan, no commercial units are operating in the United States. Economic factors have been cited as the main reason for lack of construction activity. To improve process costs, PUROX II is being developed by Union Carbide. The modified process incorporates a pressurized reactor (50-60 psig), a simplified front end, and a wastewater incinerator for cleanup. The use of moderate reaction pressures will permit higher throughputs and lower gas processing costs. Incineration of the wastewater, which usually has a biochemical oxygen demand (BOD)

Table C-11. Typical Composition of Medium-Energy Gas from the Purox-Oxygen System (Ref. C-29)

COMPONENT	AVERAGE COMPOSITION, VOL PERCENT
H_2	28.7
CO	35.2
CO_2	25.2
CH_4	5.6
OTHERS (PRINCIPALLY HYDROCARBONS)	5.3

in the 60,000 mg/ℓ range, will simplify wastewater treatment and provide steam (Ref. C-30).

C.2.3.3 Energy Efficiency

The energy efficiencies of the various steps in converting MSW to high-Btu SNG are shown in Table C-12. The reader is referred to Subsection C.1.6 for general background material, assumptions, and limitations of the energy data presentation.

Efficiencies for the first three process steps in the table are identical for the CNG and LNG. Specific parameter values are difficult to find in the literature and subject to considerable uncertainty. In addition, energy efficiencies for MSW conversion processes are less important than cost and plant reliability. Collection efficiency was estimated from typical packer-truck hauls and attendant fuel expenditures. Conversion efficiency was taken from Reference C-35 for anaerobic digestion of MSW (actual value 48 percent), but probably also approximates the thermal gasification efficiency. No values are included in the table for gas transmission or storage, because it is probable that the SNG would be produced in a large metropolitan area and injected directly into the city's gas distribution system.

Energy efficiencies for gasification of other waste products are either similar to MSW or of much less importance, and therefore are not given here.

Table C-12. Production Efficiencies for SNG from Municipal Solid Waste

PRODUCTION STEP	STEP EFFICIENCY CNG	LNG
COLLECTION	0.97	0.97
PREPARATION/CONVERSION	0.50	0.50
GAS DISTRIBUTION	0.993	NA
LIQUEFACTION	NA	0.86

C.2.4. Gasification of Liquid Hydrocarbons

The gasification of liquid hydrocarbons, such as petroleum naphtha and NGL, is a commercial technology known and used in the United States and foreign countries for many years. There are 14 facilities in this country, constructed during the 1970s, which have achieved operational status as either base-load systems or seasonal peak-shaving supply sources. Eight of the plants are designed for seasonal use only. Table C-13 shows annual production for 5 recent years. The 1980 estimate corresponds to about 0.7 percent of total gas production. The decline in production can be attributed to two factors: (1) increased availability of conventional gas, and (2) uncertainties relating to feedstock supply (Ref. C-36). DOE does not include this gas in its supply projections because of the high price of petroleum feedstocks, which supposedly makes such gas too expensive to use in the future even for satisfying peak demand (Ref. C-4).

Table C-13. Annual SNG Production from Liquid Hydrocarbons (Ref. C-36)

YEAR	PRODUCTION, BCF
1976	275.3
1977	276.7
1978	245.9
1979	191.7
1980	133.6 (EST.)

One other source of liquid hydrocarbons is oil shale. Although this resource is usually associated with liquid fuels, it has received some interest as a future source of gas supplies. While the naphtha fraction of treated and refined shale oil could be gasified in existing facilities, the more sensible and economic approach is to directly gasify the oil shale without passing through the liquid stage.

The following subsections address each of these gas sources in turn. The discussion is brief because the technology is either well established and documented, or so embryonic that little information is available.

C.2.4.1 Gasification of Naphtha and NGL

Processes used by the 14 conversion facilities in the United States are the British Gas Corporation Catalytic Rich Gas process (CRG), the Lurgi Gasynthan process, and the Japanese Methane-Rich Gas process (MRG), used in the ratio of 11:2:1, respectively. The basis of all processes for the production of gas from light hydrocarbons is catalytic steam reforming at moderate temperatures (750-950°F). Feedstocks can vary from LPG through naphtha. Limitations, besides a final boiling point of less than 400°F, include aromatic content (10 to 18 percent maximum), olefin content (1 percent maximum), and vaporization without residue.

Licensed technologies mentioned above are similar in basic concept and mature in design. Some marginal improvements may be achieved, but probably nothing that would reduce capital or operating costs by more than 5 to 10 percent. The plants have essentially no pollution problems, and have demonstrated reliable operation in large-scale units. Only the CRG process is described here.

Hydrogen-containing recycle gas and naphtha are mixed and passed through a sulfur removal unit, since the nickel-alumina gasifier catalyst is highly susceptible to irreversible sulfur poisoning. The gas stream is mixed with about 1.15 times its weight in steam, heated to reaction temperature and passed through an adiabatic reactor operating at pressures of 250 to 600 psi. The exit gas is cooled and passed through the first methanator which contains a variant of the gasifier catalyst. CO and H_2 react to form a gas containing about 35 volume percent methane and 53 volume percent steam. The gas is cooled and most of the steam condensed, then reheated to 570°F and admitted to the second methanation stage. Following CO_2 and H_2O removal, the SNG contains about 98 volume percent methane, with the balance being H_2 and CO_2.

The versatility of all the processes regarding feed changes is an important factor. Processes designed for operation on naphtha will also function on LPG and vice versa with minor adjustments. However, gasification of heavier hydrocarbon liquids, such as gas oils and crude, is more difficult. The principal problem stems from the higher fraction of carbon which they contain, with the resultant necessity to add a greater fraction of H_2 in the gasification process, and the associated increase in cost and decrease in efficiency. Additionally, the removal of sulfur becomes more difficult. No processes for these heavier feeds have been commercialized to date.

C.2.4.2 Oil Shale Gasification

Oil shale, like coal, is in abundant supply in the United States, but a number of environmental and economic problems have thus far militated against commercialization of processes for liquid fuels, although most technical problems have been solved. However, a number of technical issues need to be addressed in the direct gasification of oil shale. Development of the necessary technology was started at the IGT in 1953 under sponsorship of the AGA, and continued until 1964. The majority of work was done with Colorado shale, but a few feasibility tests were made of shale from the eastern United States and Canada. Work was begun again at IGT in 1972 and continued to 1979 under the sponsorship of the Gas Research Institute. A continuation of this R&D program is now being financed by the Department of Energy (DOE) (Ref. C-2).

Experimental results on eastern shales indicate that the use of H_2 at pressures of up to 500 psi combined with low shale heating rates allows organic carbon recoveries up to 2.5 times those achieved by conventional retorting. Thus, it is possible to recover the energy in eastern shales in amounts comparable to that which is recoverable from the richer western shales using conventional retorting methods. Development of the eastern shales for SNG production is attractive because they are close to gas markets, the socioeconomic infrastructure is favorable for large-scale manufacturing operations, and water supplies are more plentiful (Ref. C-

2). It has been reported that the Tosco Corporation is gasifying shale by reaction with steam and oxygen but no details have been published (Ref. C-18).

C.2.4.3 Energy Efficiencies

Energy efficiency data for the production of SNG from liquid hydrocarbons have not been included in this report. DOE does not consider the use of petroleum fractions for gas production economically viable and has not included this gas source in its recent forecasts (Ref. C-4). The data in Table C-13 confirm this declining trend. Gas manufacture from NGL remains a possibility, but it is too early to tell if this will be a viable option. In any event, most new supplies of NGL will be from foreign sources.

Gasification of oil shale is too remote a possibility to be used as a basis for energy calculations. The primary thrust of the oil shale program is for liquid fuels, and it is hard to imagine that these will be converted to SNG in any appreciable amounts. Finally, there are insufficient data available on which to base efficiency calculations even if the supply outlook were more favorable.

C.3 METHANOL PRODUCTION

This subsection reviews the technologies for producing methanol from several feedstock materials. A number of processes are well established both in the United States and overseas for large-volume commercial production of methanol, while others have only been carried out in the laboratory. In addition to describing production methods themselves, some background material is included on uses, specifications, current plants, feedstocks, and recent production levels. However, the methanol presentation is much briefer than the preceding coverage of SNG for two reasons. First, methanol is included only as a comparison fuel and does not represent the main thrust of the study. Second, many of the steps in the production of methanol from alternative resources such as coal, biomass, and MSW are common to either the future manufacture of SNG or the current production of methanol from NG.

It should be reiterated here that vehicle utilization of methanol is assumed to be as a neat fuel, rather than in a blend with gasoline. Thus, there is no discussion of mixing, transporting, or storing blends, and different methanol composition issues are emphasized.

C.3.1 Current Production, Uses and Specifications

Methanol is a major item of commerce, with 1981 production estimated to reach 1.2 billion gallons with a value near $1 billion (Ref. C-37). Exports are expected to be in the range of 60 to 70 million gallons, with imports near 40 million gallons. Major derivatives are formaldehyde, taking 45 percent of production, acetic acid at about 10 percent, and methyl tertiary butyl ether (MTBE) near 5 percent. Major end uses are in polymers for adhesives, fibers, and engineering plastics, accounting for 60 percent of output. Blends of methanol and other alcohols are expected to continue to grow for use as octane boosters in gasoline. Direct vehicle applications as a neat fuel are currently limited to a few demonstration fleets around the country, which account for an insignificant percentage of methanol production. During 1981, despite an expected production increase of 10 percent, plants have been running at under 85 percent of capacity (Ref. C-37).

Methanol is available in several commercial and specialty grades (e.g., reagent grade for laboratory use). Most United States producers supply a single grade that follows substantially the requirements in ASTM D 1152-77. The properties in this specification are listed in Table C-14. The Federal Specification is O-M-232F, dated June 5, 1975. There are no fuel-grade specifications or products presently available. However, there are some government and private programs under way examining possible methanol fuel modifications for use in blends (higher alcohols, corrosion inhibitors) or as a neat fuel (starting additives, water addition).

C.3.2 Manufacturing Processes from Natural Gas and Petroleum

Methanol is one of the most easily produced organic compounds. It is synthesized from a gaseous mixture of CO and H_2, with a small

Table C-14. ASTM Standard Specification for Methanol (Ref. C-40)

SPECIFICATION	AMOUNT
METHANOL CONTENT, WT %, MIN.	99.85
SPECIFIC GRAVITY, $20^{\circ}C/20^{\circ}C$	0.7920 TO 0.7930
WATER WT %, MAX.	0.10
ACIDITY, WT % AS ACETIC ACID, MAX.	0.003
ACETONE, WT %, MAX.	0.003
NONVOLATILE MATTER, MG/100 ML, MAX.	5
DISTILLATION RANGE, $^{\circ}C$	NOT MORE THAN $1^{\circ}C$, TO INCLUDE $64.6 \pm 0.1^{\circ}$
ODOR	CHARACTERISTIC, NONRESIDUAL
COLOR	NOT MORE THAN NO. 5 ON THE PLATINUM-COBALT SCALE
POTASSIUM PERMANGANATE TEST	NOT LESS THAN 50 MINUTES
SULFURIC ACID WASH TEST	NOT MORE THAN NO. 50 ON THE PLATINUM-COBALT SCALE

percentage of CO_2 added for process stoichiometry. This synthesis gas may be prepared from any feedstock containing any ratio of carbon, H_2, and O_2, as long as sulfur and N_2 levels are not too high. This covers feedstocks ranging from wood and other biomass, coal, heavy fuel oils, naphtha, and NG (Ref. C-38). Historically, NG in the United States and naphtha in Europe have been the primary feedstocks because of their low sulfur content, low cost, and ease of handling. Although naphtha is the most nearly ideal starting material from a stoichiometric viewpoint, NG is less expensive in the United States. Thus, most methanol plants are located on the Gulf Coast (Ref. C-39). This is evident from examination of Table C-15, which shows the current and near-future methanol plants in North America.

The production of methanol can be considered a two-part process (Figure C-25). The initial step is to produce a synthesis gas of proper composition from an organic raw material. The subsequent conversion and purification steps are common to all methanol production methods regardless of feedstock. Therefore, after describing the current technology for

Table C-15. Methanol Production Capacity in North America (Ref. C-41)

COMPANY	PLANT LOCATION	FEEDSTOCK	CAPACITY, 10^3 METRIC TON/YR(1) PRESENT	FUTURE	STARTUP DATE
UNITED STATES					
AIR PRODUCTS	PENSACOLA, FLA.	NG	150	150	
ALLEMANIA	PLAQUEMINE, LA	NG	300	300	
BORDEN	GEISMAR, LA.	NG/OFFGAS	480	570	1980
CELANESE	BISHOP, TEX.	NG	435	435	
	CLEAR LAKE, TEX.	NG	690	690	
DU PONT	BEAUMONT, TEX.	NG	660	825	1982
	DEER PARK, TEX	FUEL OIL	-	600	1980
GEORGIA PACIFIC	PLAQUEMINE, LA	NG	360	360	
GETTY	DELAWARE CITY, DEL.	RAFFINATE		300	
MONSANTO	TEXAS CITY, TEX.	NG	300	300	
TENNECO	HOUSTON, TEX.	NG/OFFGAS	240	390	
ARCO	GULF COAST	NG/LPG	-	600	1983
SUBTOTAL			3,615	5,520	
CANADA					
ALBERTA GAS CHEMICALS	-	NG	360	720	1982
CELANESE CANADA	-	NAPHTHA	51	51	
		NG	-	705	1982
OCELOT	-	NG	-	360	1982
WESTCOAST TRANSMISSION	-	NG	-	360	1983
SUBTOTAL			411	2,196	
MEXICO					
PEMEX	-	NG	171	825	1985
TOTAL NORTH AMERICA			4,197	8,541	

(1) ONE METRIC TON IS EQUIVALENT TO 335 GALLONS.

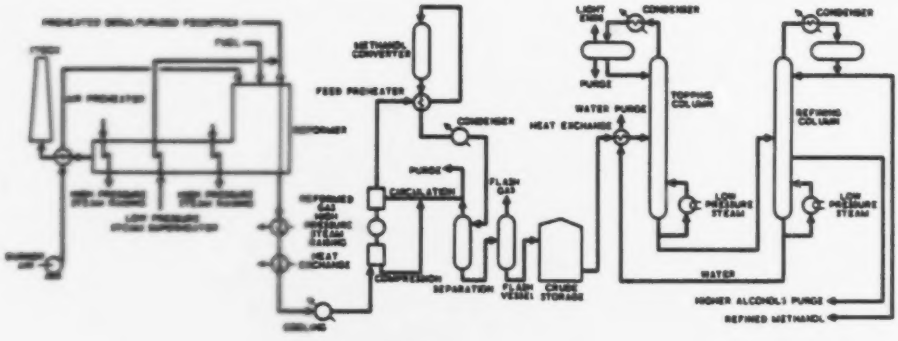

Figure C-25. Generic Flow Diagram for the Methanol Production Process (Ref. C-42)

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methanol manufacture from methane, subsequent discussions of production from other feedstocks will cover only the initial step.

The preparation of a syngas from NG (methane) is accomplished by steam reforming according to the equation:

$$CH_4 + H_2O \overset{cat}{\rightleftharpoons} CO + 3H_2 \qquad \text{(Eq. C-1)}$$

The endothermic reaction is carried out in a tubular reformer over a nickel catalyst operating near 850°C at 15 to 20 atmospheres. However, methane feedstock is unique in that it contains too much H_2 for methanol synthesis. This can be seen from the synthesis equation:

$$CO + 2H_2 \overset{cat}{\rightleftharpoons} CH_3OH \qquad \text{(Eq. C-2)}$$

In order to attain the proper ratio of reactants, some CO_2 is added, since it requires more H_2 in the synthesis step:

$$CO_2 + 3H_2 \overset{cat}{\rightleftharpoons} CH_3OH + H_2O \qquad \text{(Eq. C-3)}$$

For this reason, many manufacturers attempt to locate their plants near convenient sources of excess CO_2, such as ammonia plants.

The catalytic conversion to methanol is the critical production step. The type of catalyst used and the operating conditions significantly affect plant capital and operating costs. Production processes are offered by a number of companies. The Imperial Chemical Industries' (ICI) low-pressure process has been used in 14 plants since 1970, and the Lurgi process in at least eight that are operating or under construction (Ref. C-29). A third alternative, the CPI-Vulcan process developed by Vulcan-Cincinnati, has some unique features that distinguishes it from most others. These three commercial technologies are outlined below, with emphasis on the ICI process because of its preeminence in the field. One process in development by Chem Systems is also briefly described.

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The key to methanol catalysis involves choosing a highly selective catalyst which does not promote carbon-carbon bond linkage. ICI, during the late 1960s, pioneered the development of an active copper catalyst which allowed low-pressure (50 to 100 atmospheres) operation compared to previous processes operated at high pressures (100 to 300 atmospheres). A number of benefits accrue from the lower pressures. However, over the past decade, ICI operating pressures have tended to increase within the above range to reduce equipment size.

The synthesis gas is compressed by a turbine-driven centrifugal compressor, mixed with recirculating gas and fed to the converter. The converter is a pressure vessel containing a single catalyst bed. Since the methanol formation reactions are exothermic, and the catalyst is deactivated at high temperatures, the converter temperature must be controlled in the 200 to 300°C range. In the ICI process, this is accomplished by cold syngas injection at several levels. As long as sulfur in the syngas is practically nil, the catalyst retains its high activity, and a life of up to 4 years is claimed.

The converter gas is cooled and the methanol condensed. Because the conversion per pass is relatively low, on the order of 5 percent, a large quantity of gas must be recirculated to the converter. The crude methanol passes through two distillation steps to remove high- and low-boiling impurities. A third column is sometimes used to meet very tight product specifications.

The Lurgi low-pressure methanol process uses a tubular reactor. It operates at pressures between 40 and 55 atmospheres, and temperatures of 250 to 265°C. The synthesis gas is compressed to the synthesis pressure by a turbine-driven centrifugal compressor before it is mixed with recirculating gas. If the makeup gas originates from a gasifier process operating at around 40 atmospheres, no compression is necessary. After being heated in a heat exchanger, the mixture enters the synthesis reactor for conversion to methanol. The reactor is a shell-and-tube type, with a copper-based catalyst contained within the tubes, which are

surrounded by boiling water. Synthesis gas is passed through the catalyst, and the heat of reaction is used to boil the water for use as high-pressure process steam.

The methanol gas leaving the reactor is cooled by exchanging its heat with incoming synthesis gas and, if necessary, with air or water. The condensed crude methanol is flash-separated, and the unreacted gas is recycled to the catalyst. The crude methanol stream is processed in distillation columns as in the ICI process.

The CPI-Vulcan process uses a quenched-bed reactor, operating at pressures in the range of 100 to 300 atmospheres. Seven plants operating worldwide are reported to be using the process. A turbine-driven centrifugal compressor is used to compress the synthesis gas prior to entering the converter. The converter consists of multiple catalyst beds, with cold gas injected between beds to control the process temperature. The Vulcan process is of interest because the characteristics of the basic methanol synthesis catalyst can be modified to obtain various levels of selectivity, and the process can be operated over a broad range of pressures. It is capable of producing methanol containing varying quantities of the higher alcohols, which are normally considered by-products for chemical-grade methanol. The presence of higher alcohols is desirable for methanol fuel applications because of their higher heating value per unit weight compared to methanol.

The Chem Systems methanol synthesis process, which is now under development, employs a bubbling bed reactor, and operates at a pressure of 30 to 50 atmospheres and temperatures in the range of 275 to 350°C. Major components of the system are a zinc oxide drum (for trace H_2S removal), a three-phase fluidized bed reactor that employs a nonmiscible hydrocarbon liquid, and a cooling unit for condensation of the methanol product.

In operation, the synthesis gas, which has undergone a previous acid-gas removal step, is passed through the zinc oxide bed to reduce sulfur below 0.25 grain per scf. It is then mixed with recirculating (unreacted) syngas, and the combined stream is fed to the reactor. The

feed gas passes upward through the bubbling bed catalytic reactor, together with recycle oil. The heat generated by methanol synthesis is absorbed by the hydrocarbon oil and is used to generate steam for the turbine/compressor. It is claimed that use of the oil permits much closer temperature control in the reactor, and thereby very close control over the composition of the methanol product. At the top of the reactor, the oil and gas are separated. The oil passes to a surge drum and is recirculated to the reactor via a waste-heat boiler. The overhead gas from the reactor is cooled in successive stages. First, it is split into two streams used to heat feed gas and recycle gas. The two streams are combined and cooled again to condense the methanol, which is withdrawn to storage. The remaining synthesis gas is recycled via a compressor, with a portion being purged to reduce inerts and control composition. The purged gases are used as fuel gas elsewhere in the system. The methanol product contains over 95 weight percent methanol, about 2 percent higher alcohols and 2.5 percent water. It can be distilled to obtain higher purity methanol if required. A major advantage claimed by Chem Systems for the process is higher conversion per pass, about 20 percent versus 5 percent in most other processes, substantially reducing recycle flow (Ref. C-29).

Petroleum naphtha can be used in place of NG, and in fact it was the original feedstock for the ICI process in Europe. It is also steam reformed according to the reaction:

$$CH_{2.2} + H_2O \xrightarrow{cat} CO + 2.1\ H_2 \qquad \text{(Eq. C-4)}$$

In this case, the H_2/CO ratio is exactly that required for methanol synthesis and no CO_2 addition is required.

In the case of fuel oil feed, the process is somewhat different because it is necessary, in catalytic steam reforming, that the hydrocarbons vaporize completely without carbon formation. This cannot be done with heavy fuel oil. The alternative is a partial oxidation process in the presence of steam. In the Lurgi process, as an example, the oil is partially oxidized by oxygen and steam at 1400 to 1450°C and 60 atmo-

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spheres. Product gas consists of equal parts of H_2 and CO with small quantities of CO_2, CH_4, H_2S and free carbon. It is scrubbed with water to remove carbon, and then cooled. The carbon is recovered and recycled to the reactor. After desulfurization, part of the gas is sent to a shift converter operating at about 290°C to adjust the H_2/CO ratio to near 2 by the reaction:

$$CO + H_2O \overset{cat}{\rightleftharpoons} CO_2 + H_2 \qquad \text{(Eq. C-5)}$$

After CO_2 removal, the gas streams are united and sent to the synthesis reactor. Because the pressure after CO_2 removal is about 50 atmospheres, no synthesis gas compressor is required.

C.3.3 Methanol Production from Coal

Coal can be liquefied indirectly by gasification to a suitable synthesis gas and subsequent conversion to methanol, with the conversion step accomplished by any of the processes described previously for NG. Furthermore, the gasification of coal to a synthesis gas differs only in a few details from the gasification of coal for the production of SNG. Therefore, the following discussion focuses on the difference between coal gasification to a syngas composition and to SNG.

No plants have yet been built in the United States using coal as the feedstock. However, a number of studies have been conducted of this route, and some of the findings are presented here. In brief, the coal is prepared for processing in a manner similar to that for SNG, governed by the requirements of the particular gasifier selected. It is gasified in a partial oxidation process by steam and oxygen as before, but the gasifier operating conditions are different since the desired products are CO and H_2 rather than CH_4. The raw gas is treated to remove any CO_2 and H_2S present, then shifted to a H_2/CO ratio of about 2 rather than the ratio of 3 needed for methanation in SNG production. The CO_2 formed in the shift reaction is removed, and the treated syngas then goes to a conventional methanol synthesis unit, as described in the previous section for NG.

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Inasmuch as methanol production from coal benefits from economies of scale, gasifiers capable of high throughputs are preferred. This implies a preference for entrained-flow gasification (e.g., Koppers-Totzek, Texaco, and others) which maximizes coal and gas throughput for a fixed gasifier diameter and pressure. Entrained-flow gasification also produces higher H_2 and CO composition and lower amounts of by-products (e.g., methane and hydrocarbons) than moving-bed or fluid-bed gasification (Ref. C-4). However, if both methanol and SNG can be marketed, their coproduction can be accomplished by, for example, a moving bed gasifier such as Lurgi at an improvement in thermal efficiency of 8 to 10 percent (Refs. C-21 and C-43).

Gasifiers operate at significantly higher temperatures, near 3000°F, in the production of methanol synthesis gas than in SNG manufacture (Ref. C-44). The process from coal differs from that using NG in that the former is H_2-deficient and requires carbon removal as CO_2, while the latter is H_2-rich and needs carbon addition as CO_2. From an economic viewpoint, the use of coal as a feedstock, rather than NG, greatly increases the cost of the plant. The major reasons for this increase are (1) the cost of coal handling, preparation and feeding, (2) the cost of the gasification section and oxygen plant, and (3) the cost of gas cleanup and waste handling facilities, which must meet stringent requirements for sulfur and particulate removal for both process and environmental reasons. The syngas purification section must have ample provisions for coping with process upsets, to prevent excessive amounts of sulfur compounds and other impurities from reaching the methanol synthesis loop. This problem is less critical when NG is the feed, since it is already essentially sulfur-free. With coal, however, the possibility of shutting down the entire facility by poisoning the methanol catalyst is always a problem, and design features such as redundancy, sparing, and protective instrumentation are necessary (Ref. C-45).

C.3.4 Methanol Production from Biomass and Waste

It is convenient to group biomass and waste resources together for this discussion because they have many points of processing

similarity. A unified approach appears particularly justified after the previous process review in connection with SNG production. Figure C-26 indicates the two routes to methanol synthesis.

Several preliminary observations can be made. Anaerobic digestion is not an attractive technique for producing methanol. The natural product from digestion is methane and there is generally a sufficient market for it, either in or adjacent to the plant, or nearby via pipeline, that further processing is not justified on economic or energy grounds. Furthermore, methanol plants benefit from economies of scale, whereas digestion facilities processing dilute slurries become excessively large as output grows. In light of these facts, and the additional observation that all pertinent technologies have been described in previous sections, it appears logical to concentrate on the thermal gasification alternative.

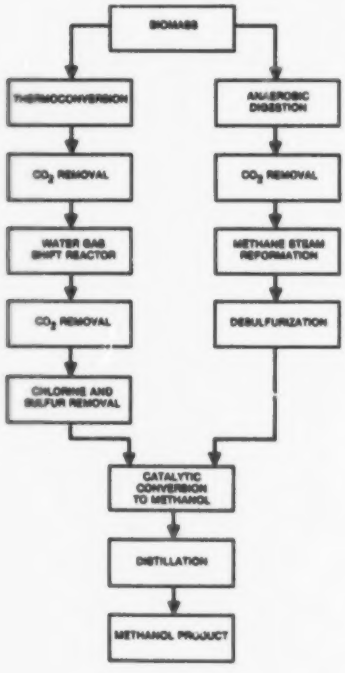

Figure C-26. Block Diagram of Methanol Production Using a Thermoconverter or an Anaerobic Digester (Ref. C-29)

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The PUROX process developed by Union Carbide Corporation for processing MSW has been described in connection with SNG production. The output gas appears better suited as a synthesis gas for methanol than as a starting point for SNG. However, it would still have to be processed to remove particulates, CO_2 and H_2S. The shift reactor is needed to adjust the H_2/CO ratio, after which the process is essentially the same as for NG feedstock. The process has been tried with wood chips with some success (Ref. C-46). The same reference describes a Battelle Columbus Laboratories process that is quite different. The Battelle process employs a fluidized bed gasifier with hot sand circulated to provide gasification heat. The hot sand is heated in a separate combustor that burns wood char. Circulating the sand eliminates the need for an oxygen plant and could reduce energy requirements.

A number of other processes are in development for gasifying wood, including Wright-Malta, Battelle-Northwest, Winkler, Hoechst-Uhde variation of Winkler, and a twin fluidized bed process by EBERA Manufacturing Co. of Japan (Ref. C-29). Many of these approaches were initially developed for coal gasification and modified for operation on wood. In addition, the objective is often to produce only a medium-Btu gas, and gasifier operation would have to be changed to optimize synthesis gas production. Additional development and demonstration are required in most cases before a commercial-size plant could be considered.

C.3.5 Energy Efficiency

The energy efficiencies associated with the various steps in producing methanol from NG, coal, wood, and MSW are shown in Table C-16. The reader is referred to Subsection C.1.6 for general background material, assumptions, and limitations of the energy data presentation.

Starting with methanol from NG, the current production source, the first two steps are common to all NG processing. The conversion step efficiency of 64 percent is taken from References C-38 and C-47. Rail transport efficiency was computed from data in Reference C-6. In the case of coal, the first two steps were given in connection with SNG production

Table C-16. Production Efficiencies for Methanol from Natural Gas, Coal, Wood, and MSW

RESOURCE	PRODUCTION STEP EFFICIENCY
NATURAL GAS	
EXTRACTION AND GATHERING	0.964
PROCESSING	0.968
STEAM REFORMING AND SYNTHESIS	0.64
RAIL TRANSPORT(1)	0.98
COAL	
SURFACE MINING	0.986
COAL PROCESSING	0.95
COAL CONVERSION	0.62
RAIL TRANSPORT(2)	0.98
WOOD	
HARVESTING	0.978
LOCAL TRANSPORT	0.979
WOOD CONVERSION	0.55
RAIL TRANSPORT(2)	0.98
MUNICIPAL SOLID WASTE	
COLLECTION	0.97
PROCESSING AND THERMAL CONVERSION(3)	0.40

(1) BASED ON METHANOL SHIPMENT TO CHICAGO AREA FROM GULF COAST PLANT.
(2) BASED ON METHANOL SHIPMENT TO CHICAGO AREA FROM WESTERN U.S.
(3) ASSUMES LOCAL USE OF METHANOL PRODUCTION.

from coal. Coal conversion efficiency for methanol was taken from References C-43 and C-48, assuming coproduction of methanol and SNG.

For the conversion of wood to methanol, the only new value is the conversion step itself. Little data are available because relatively little development work has been done; the 55 percent value given in the table is rounded off from data given in Reference C-32. In the case of MSW conversion, the 40 percent efficiency is from Reference C-46, assuming thermal gasification of the waste. Except for methanol from NG,

the other conversion values are speculative pending performance data from commercial facilities.

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C.5 GLOSSARY

Some of the more important terms used in this appendix are defined as follows.

Acidogens	Acid-forming bacteria that can convert the organic matter in sewage and solid waste to intermediate degradation products during the first stage of anaerobic digestion.
Anaerobic digestion	A two-stage process in which organic materials are broken down, in the absence of air, into a biologically more stable residue with the evolution of methane and carbon dioxide.
Aquifer	Underground water-bearing permeable rock, sand, or gravel.
Associated/dissolved natural gas	Gas occurring in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
Baseload	A subdivision of the total demand profile for electricity. This load category refers to those plants which operate continuously, except for maintenance requirements, to satisfy demand.
Biomass	Organic matter, such as trees, crops, aquatic plants, and manure, that is available on a renewable basis.

BOD	Biochemical oxygen demand: the quantity of oxygen required by bacteria to oxidize the organic matter in a waste stream.
Boiloff	Vaporization of cryogenic liquid due to heat influx from the ambient environment through tank supports and insulation.
Borehole	A hole (well) drilled in the earth for the purpose of removing fluid from a reservoir or injecting fluid into a reservoir.
Bore shooting	A traditional technique for well stimulation in Devonian shale by detonating gelled nitroglycerine in the producing section.
Coking coal	Coal that softens and agglomerates when heated.
Cascade cycle	System in which a series of separate refrigerants is used to obtain discrete, increasingly lower temperature levels.
Char	A mixture of ash and carbon which remains after partial combustion or heating.
Conventional natural gas	Gas produced by conventional techniques from gas in permeable deposits, usually restricted to the lower 48 states.
Corn stover	Cornstalks excluding the grain.
Cryogenics	Production and use of extreme cold, generally at temperatures below -150°F.
Cushion gas	That portion of the natural gas in underground storage that remains in the ground to provide driving pressure for rapid gas delivery when needed; about one-third to one-half of the stored gas falls in this category.
Development wells	Wells drilled to increase production in established fields.
Devonian shale	Geologic formations underlying an area of approximately 250,000 square miles in the middle and eastern United States. These shales, deposited during the Devonian period, contain natural gas in fractures and micropores and are one target of enhanced gas recovery.

Dolomite	A calcium-magnesium carbonate mineral found as crystals and in extensive beds as a compact limestone.
Endothermic	A chemical reaction that absorbs heat.
Enhanced gas recovery	Increased recovery of natural gas from a reservoir through the external application of physical or chemical processes, such as hydraulic fracturing.
Entrained bed gasifier	A coal gasification process in which pulverized coal is carried along in a gas stream.
Exothermic	A chemical reaction that produces heat.
Expanded bed reactor	An advanced type of anaerobic digester akin to a fluidized bed with methanogenic bacteria attached to inert solid particles.
Exploratory well	Well drilled to find gas in an unproved area, to find a new reservoir in a known field, or to extend the limit of a known reservoir.
Flash separation	A method of separating fluid components of different volatility by rapid reduction of the pressure on the liquid.
Fluidized bed	Type of gasifier in which the pyrolysis or combustion material is suspended by an updraft gas stream.
Fracturing	Splitting or cracking by explosion or high pressure fluid to make a rock formation more permeable.
Gas-cap gas	Another name for associated natural gas (see Associated).
Geopressured gas	Methane contained in underground brine reservoirs in which the fluid is confined under pressure significantly greater than normal hydrostatic pressure, developed principally by the weight of overlying rocks and sediment.
High-Btu gas	Gas containing predominantly methane with a higher heating value above 900 Btu per cubic foot.
Hydrates	Solid, snow-like compounds formed by the union of water with methane or other light hydrocarbons.
Hydrogasification	The direct reaction of carbon or hydrocarbons with hydrogen to produce methane.

Hygroscopic	The property of a solid or liquid to remove water vapor from a gas stream.
In situ gasification	Combustion of unmined coal at its natural underground site. Procedure involves drilling wells into the coal seam and igniting the seam in the presence of air or oxygen and often steam.
Joule-Thomson expansion	Expansion of a fluid from a higher pressure to a lower pressure through a valve or porous plug under adiabatic conditions.
Kelp	A large brown seaweed.
Lens	Sedimentary deposit of irregular shape surrounded by impervious rock.
Lenticular sand	Discrete, discontinuous, lens-shaped sand bodies within a formation.
Lignite	Brownish-black coal in which the alteration of vegetal matter has proceeded further than peat, but not as far as subbituminous coal.
LNG	Liquefied natural gas: gas that has been liquefied by cooling to minus 260°F.
Low-Btu gas	Gas obtained by combustion of coal or other organic material with air and having a higher heating value of 100 to 250 Btu per cubic foot.
LPG	Liquefied petroleum gas: a gas containing certain hydrocarbons that are gaseous under normal atmospheric conditions, but can be liquefied under moderate pressure at normal temperatures. Propane and butane are the principal examples.
Medium-Btu gas	Gaseous fuel produced from coal or biomass with a higher heating value of 300 to 750 Btu per cubic foot, suitable for use in boilers or direct heat applications.
Mercaptan	Any of various organic compounds containing a sulfur and hydrogen group (-SH) and a hydrocarbon group such as $-CH_3$. These compounds usually have a disagreeable odor and are often added to natural gas as odorants.
Mesophilic operation	A method of operating anaerobic digesters wherein the temperature is maintained between 86 and 105°F.

Methanator	A reactor in which a mixture of carbon monoxide and hydrogen is catalytically and exothermically converted to methane and water.
Methanogens	Bacteria which can convert volatile organic acids to methane and carbon dioxide under anaerobic conditions.
Millidarcy	Unit of permeability.
Mixed refrigerant cycle	Variation of the cascade cycle involving the circulation of a single refrigerant stream which contains a mixture of refrigerants such as butane, propane, ethane, methane, and nitrogen.
Molecular sieves	A crystalline form of sodium-alumina-silicate that strongly adsorbs water and acid gases.
Naphtha	Any of various volatile, often flammable liquid hydrocarbon mixtures having properties intermediate between gasoline and kerosene. Used as solvents and diluents and as raw materials for conversion to gasoline and SNG.
Natural gasoline	A highly volatile type of gasoline recovered from natural gas. Includes butanes, pentanes, and heavier hydrocarbons.
NGL	Natural gas liquids: liquid hydrocarbon mixtures which are gaseous at reservoir temperatures and pressures but are recoverable by condensation or absorption. Typical examples are natural gasoline and LPG.
Nonassociated natural gas	Natural gas not in contact with crude oil in a reservoir.
Oil shale	Sedimentary rock containing insoluble organic matter (kerogen) which can be converted into oil by heating.
Odorant	A gaseous chemical compound with a distinctive odor added to natural gas for leak detection and consumer protection. Typical examples are mercaptans, aliphatic sulfides, and cyclic carbon-sulfur ring compounds.

Partial oxidation	A noncatalytic process for converting gas or liquid hydrocarbons, including heavy fuel oil, to hydrogen and carbon monoxide (synthesis gas) using steam and oxygen.
Peakload	A subdivision of the total demand profile for electricity. This load category requires intermittent operation of plants designed to respond to the highest levels of demand.
Peat	A precursor of coal, consisting of vegetation which has been deposited in bogs at the land surface under conditions of moderate to high rainfall and partial isolation from local drainage systems.
Perlite	A granular glass insulating material with a honeycomb structure manufactured from volcanic rock by heating in a kiln.
Permeability	An index of the ability of reservoir rock to transmit fluids under the influence of a pressure gradient.
pH	Technically, the logarithm of the reciprocal of the hydrogen ion concentration; used to indicate acidity or alkalinity.
Porosity	Ratio of void volume to total volume of reservoir rock.
Proppant	Solid material, usually sand, injected during hydraulic fracturing to prevent the fracture from closing on termination of pumping.
Quad	Unit of energy equivalent to 10^{15} (quadrillion) Btu.
Reserves	See Table 6-1.
Resources	See Table 6-1.
Satellite LNG facility	An installation located at some distance from a central liquefaction source and designed to satisfy peakload demands. Usually contains only storage and regasification equipment, automatically operated.
Shift conversion	A step in the process of converting coal, biomass, or natural gas to methane by catalytically reacting carbon monoxide and steam to produce hydrogen and carbon dioxide.

Slagging gasifier	Gasifier that operates at temperatures high enough to effect fusion of the fuel's ash content.
SNG	Synthetic or substitute natural gas: gas manufactured from coal or biomass but sometimes extended to include naphtha as a feedstock.
Subbituminous coal	A coal with low fixed carbon and high percentages of volatile matter and moisture; heating value between bituminous coal and lignite.
Subsidence	Sinking or lowering of the land surface due to underground excavation or formation weakening.
Synthesis gas	Gas containing principally hydrogen and carbon monoxide and used as feedstock for catalytic conversion to methanol.
Thermal gasification	Application of heat, directly or by partial combustion, to biomass material, forming char and gases, principally hydrogen, carbon monoxide, and carbon dioxide.
Thermophilic operation	A method of operating anaerobic digesters wherein the temperature is maintained between 120 and 140°F. Microbiological activity is increased compared to mesophilic operation but there are attendant process difficulties.
Tight gas reservoir	Sandstone formations containing natural gas, most commonly in western United States. These formations generally have low porosities and permeabilities, therefore not amenable to conventional gas recovery techniques.
Unconventional natural gas	Gas located in formations not conducive to recovery by conventional means. The category usually includes gas in coal seams, Devonian shale, geopressured brines, and tight gas reservoirs.
UCG	Underground coal gasification: see In Situ Gasification.
Water hyacinth	Rapidly growing freshwater plant of the lily family.

APPENDIX D

REVIEW COMMENTS

APPENDIX D
REVIEW COMMENTS

The organizations listed in Table D-1 reviewed the draft versions of the body of this report and, later, the Executive Summary. The valuable assistance provided by these organizations is hereby gratefully acknowledged. Many constructive comments were received and, where appropriate, these are reflected in the final report.

At the specific request of the American Gas Association and Beech Aircraft Corporation, copies of their review comments are reproduced in this appendix.

Table D-1. Organizations Which Reviewed Draft Versions of This Report

	ORGANIZATION	CONTACT
1.	AMERICAN GAS ASSOCIATION ARLINGTON, VIRGINIA	RANDALL I. COLE
2.	ARGONNE NATIONAL LABORATORY ARGONNE, ILLINOIS	MARTIN J. BERNARD III
3.	BEECH AIRCRAFT CORP. WICHITA, KANSAS	ROY E. ADKINS
4.	CNG SERVICES, INC. LNG SERVICES, INC. PITTSBURGH, PENNSYLVANIA	ROBERT E. PETSINGER
5.	DUAL FUEL SYSTEMS, INC. MONTEBELLO, CALIFORNIA	WILLIAM DAWSON
6.	ESCHER: FOSTER TECHNOLOGY ASSOCIATES, INC. ST. JOHNS, MICHIGAN	WILLIAM J.D. ESCHER
7.	FORD MOTOR COMPANY SCIENTIFIC RESEARCH LABORATORIES DEARBORN, MICHIGAN	ROBERTA NICHOLS
8.	GAS SERVICES ENERGY CORPORATION KANSAS CITY, MISSOURI	JOHN E. WRIGHT
9.	GENERAL MOTORS CORPORATION ENVIRONMENTAL ACTIVITIES STAFF WARREN, MICHIGAN	G.F. STOFFLET
10.	INSTITUTE OF GAS TECHNOLOGY, CHICAGO, ILLINOIS	D.P. GREGORY
11.	MUELLER ASSOCIATES, INC. BALTIMORE, MARYLAND	RICHARD L. BECHTOLD
12.	NCF INDUSTRIES LOS ALAMITOS, CALIFORNIA	NORMAN C. FAMLEY
13.	NEW YORK STATE ENERGY OFFICE ALBANY, NEW YORK	ELLEN R. BOGARDUS
14.	UNITED STATES ENVIRONMENTAL PROTECTION AGENCY WASHINGTON, D.C.	GEORGE D. KITTREDGE
15.	UNITED STATES GENERAL SERVICES ADMINISTRATION, VEHICLE ENGINEERING BRANCH WASHINGTON, D.C.	ROBERT L. ULLRICH

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AGA American Gas Association

1515 Wilson Boulevard, Arlington, Va. 22209
Telephone (703) 841-8400

October 2, 1981

Mr. Ralph D. Fleming
CE-131.2
U.S. Department of Energy
Washington, DC 20585

Dear Mr. Fleming:

The American Gas Association ("A.G.A.") is pleased to have an opportunity to comment on "Assessment of Natural Gas Application to Automotive Vehicles" prepared for the U.S. Department of Energy, Office of Vehicle and Engine R&D, under contract to the Aerospace Corporation, El Segundo, California. The A.G.A. has a continuing interest in the utilization of methane as an automotive fuel. It has met on several occasions with representatives of your office and of Aerospace in an effort to contribute to a thorough assessment.

The Report pulls a large amount of data and information together and will provide a useful reference for that purpose. We are encouraged by this effort concerning methane powered vehicles and look forward to an opportunity to discuss our comments with you and contribute to your future efforts.

The Executive Summary was "in preparation" as indicated by our copy of the Draft Report. Based on the lack of summaries in all sections, it is difficult to assess what Aerospace's overall conclusions are. We would appreciate an opportunity to review this summary when completed and suggest that each of the major eight sections have a summary prepared.

Several general comments are in order. We suggest additional attention be given to the topic of new R&D developments for methane powered vehicle ("MPV") technology and the inherent advantages stemming from this new technology. MPV developments are occurring rapidly; however, this Draft Report provides inadequate insight and perspective on their developments. Examples are the use of activated carbon, molecular sieves, silica gels and molded containers. Section 8, Research Needs, should reference the storage concept developments. Concepts such as these have potential economic and practical benefits; for example, the storage of CNG at lower pressures in the presence of activated carbon, etc. or the storage of CNG at greater pressures than can now be done with existing cylinders. Aerospace

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should also consider research recommendations on enhanced containment systems for LNG boiloff - such boiloff being considered a hazard by them.

The Report does not address institutional barriers and makes no research recommendations concerning them. A.G.A. recommends that an assessment of the MPV should include evaluations of refueling station infrastructure; federal and state subsidies for competitive fuels such as electricity and gasohol; improved regulatory attitudes concerning vehicle use, station siting and storage designs; and impediments to fleet development because of capital investment costs.

Section Three, in general, needs additional development of current and future economics of the major competing fuels in the transportation market. For example, the Draft Report fails to draw any conclusions and in fact concludes with a discussion of wellhead price decontrol rather than answer the fundamental question of a sufficient supply of gas existing to support this market. While A.G.A. firmly believes that such a supply does exist, it would seem that the summary for the 182-page analysis of the subject should answer this fundamental question. We also would observe that approximately half of the Draft Report was devoted to the subject of supply and economics.

Specific comments follow. They are presented in the same sequence as the major sections appear and refer to page number and sections.

The first paragraph of Section 2.2.1.1 discusses Table 2-1, which purports to show a distinction between LNG and natural gas. A.G.A. would suggest that this distinction is not portrayed and in fact cannot be made because of the variance in the constituent gases of both, depending on geographical location and source. (See for example Table 2-3). In addition, the paragraph contains a non sequitur in that the boiling point for methane and natural gas, while suggested by the text to be "one of the most different properties for the fuels", is in fact the same, -259°F.

Section Three, Supply and Economic Assessment, represents a relatively long look at different conventional and supplemental gas supply sources. It never reaches, however, any conclusion on a likely range of gas availability over time. Further, the report totally ignores the issue of gas demand. The availability of gas for use in the transportation sector is not only dependent on gas supply availability but also what likely demand exists for that gas. Given recent

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conservation trends, several updated government and independent forecasts have projected significantly lower total energy and gas energy requirements over time (particularly in traditional markets). The attached A.G.A. energy conservation analysis documents this trend. In fact, the "low-end" gas supply estimate for 1990 in the Aerospace report -- taken from the DOE/EIA 1980 Annual Report -- (see Table 3-43) is demand constrained. If a market for gas in transportation had developed by 1990, that EIA 1980 Annual Report would have anticipated more than adequate supplies to satisfy that demand level.

Detailed discussion of the resource base, production technology and range of potential production of potential gas supplies over time is unnecessary to the basic purpose of the Report. The question that needs to be answered is whether sufficient gas supplies will be available to satisfy a growing demand for gas in the transportation sector. To answer that question, supply and demand must be examined together. Given recent trends in both gas supply and demand, the premium nature of gas demand within the transportation sector and the demand-pull nature of many gas supplemental supplies, it is obvious that sufficient gas supplies can exist to satisfy at least a limited (i.e. fleet vehicles) penetration of methane into the transportation market.

Section Four examines the issue of thermal efficiency of competing MPV systems in several sub-sections. The question of thermal efficiency is important to the calculations of cost estimates of competing fuels and conservation of domestic resources. In this regard the coal processing efficiency, shown as 95% in the report in Table 4-2 for synthetic gas, was already included in the coal conversion efficiency number, shown as 65%. Second, the 93% efficiency listed for the gas pipeline system, Table 4-1, is unrealistically low. Most independent estimates place pipeline delivery efficiency at 97%. The citation used by the Report for the gas transmission efficiency, Energy Balances in the Production and End-Use of Methanal Derived Coal (U.S. Department of Energy, December 10, 1980), is inadequate.

Section Six, Safety, presents an examination of the safety of gaseous fueled vehicles relative to conventional fueled vehicles. We find no evaluation of the latter however.

The safety record of methane powered vehicles in Italy is impressive. Compressed natural gas has been in use in Italy since the 1930's and some 250,000 vehicles are operated on this fuel. In contrast, the Draft suggests at page 6-44 that "the available information on methane vehicles does not constitute an adequate basis for conclusions regarding the supply of this fuel...". We disagree with this conclusion.

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Section 6.3.1., Physical Properties, page 6-13, considers LNG spillage issues. Reference is made to large-scale LNG Spills. Since the DOE Liquefied Gaseous Fuel Safety Program is referenced on the same page, we would suggest that the phrase "(liquid volumes of several cubic meters)" be changed to refer to several hundred cubic meters so as to accurately portray this Safety Program. Spills of several cubic meters are considered to be of a small-scale nature. Section 6.3.2., Thermo-chemical Properties, refers to LNG spill fireballs. The previously referenced DOE Safety Program has discounted the fireball issue and we would recommend that the outdated Reference 6-43, which precedes the DOE Safety Program, be updated.

Section 6.3.4, Relative Hazards based on Fuel Properties, presents a methodology for comparing fuel hazards based on their thermo-chemical and physical characteristics. We agree that an approach such as this can provide a useful perspective concerning relative characteristics. We do suggest however, that the term "leakage" is not an appropriate parameter for comparing fuels based on their properties. Leakage is a function of accident conditions, codes, standards, operating practices and operator training, rather than storage pressure or fuel viscosity.

The A.G.A. appreciates DOE interest in our views and is ready to contribute as needed to what many within the A.G.A. organization feel is a very worthwhile report. Please contact me at 841-8654 if you would like to discuss any of our comments.

Sincerely,

Randall I. Cole

Randall I. Cole
Manager
Energy Resources Development

RC: rr

Enclosure

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ENERGY ANALYSIS

American Gas Association

Policy Evaluation & Analysis Group
American Gas Association
1515 Wilson Boulevard
Arlington, VA 22209
703-841-8400

1981-3 March 20, 1981

A SURVEY OF ACTUAL AND PROJECTED CONSERVATION IN THE GAS UTILITY INDUSTRY: 1973-1990

A. Introduction

The development of a sound national energy policy must include consideration of the contribution of energy conservation now and in the future. For the gas utility industry, energy conservation represents both a commitment to the efficient use of our natural resources and an opportunity to serve additional customers. In addition to the significant levels of conservation already experienced to date through utility-sponsored programs and customer-initiated actions, several ongoing and proposed Federal and state conservation-oriented programs could have a major impact on the gas industry, e.g., the Residential Conservation Service (RCS) program and Building Energy Performance Standards (BEPS).

In response to the need to improve our understanding and to assess the role of gas utilities with respect to present and future conservation policies, A.G.A. recently conducted a special survey of gas utility companies of varying sizes representing 60% of 1979 gas utility end-use sales and reflecting all regions of the U.S. The survey elicited both quantitative information about present and projected levels of conservation and qualitative information regarding company programs and views on key conservation issues.

B. Executive Summary of Results

Quantitative results from the gas utility conservation survey indicate that in the 6 years following the 1973 oil embargo, gas conservation (defined herein as the percent decline in gas use per customer adjusted for weather from the 1973 baseline) has increased nearly every year in all 3 customer classes surveyed in all regions of the U.S. For the decade of the 1980s, gas conservation is expected to continue to increase annually but at a slower rate.

- In the residential sector, gas use declined at a rate of 2.7% per year, resulting in 15% less gas consumption during 1979 relative to the 1973 base.

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- Residential spaceheating use specifically showed an even greater annual decline than residential gas use generally due to conservation over the 1973-79 period (3.7% per year), with a total decline in 1979 of 20% compared to 1973 levels.

- Total residential conservation is projected to grow at a lower rate of 1.2% per year over the 1980-90 period, reaching a level in 1990 of 26% compared to the 1973 base.

- The commercial sector showed lower overall levels of conservation in 1973-79 compared to the residential sector, reaching 12.4% in 1979; the annual rate of decline in consumption was in a similar range--2.2% per year.

  - Commercial conservation is projected to grow at a significantly lower annual rate during the 1980s, approximately 0.4% per year, reaching a level of 16% in 1990 compared to the 1973 base.

- Industrial gas conservation (i.e., as opposed to conversion from gas to other fuels) has thus far been lower than either the residential or commercial sectors, reaching a level of about 9% in 1979, or a decline in use of 1.6% per year through 1979.

  - Industrial conservation is projected to reach a level of 18% by 1990, a decline in use of 0.8% per year through the 1980s.

- Survey respondents generally agreed that additional inexpensive primary conservation, such as thermostat set-backs, is achievable and likely, but that more expensive secondary measures (insulation, new efficient appliances, etc.) will account for greater shares of gas conservation in the future, thereby moderating the rate of conservation expected in the 1980s.

  - The most important markets cited by the survey respondents for the consumption of conserved gas in 1985 and 1990 varied by region. Companies in the industrial Midwest tended to focus on increased gas

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- The most frequently cited reasons why conservation is actively promoted by gas utility companies were:
  - to ease the burden of higher prices on customers.
  - to support national objectives regarding conservation of non-renewable energy sources.
  - to enhance proved supplies to meet the needs of existing and new customers, and to allow time for needed potential and supplemental supplies to come onstream.
- In designating the factor with the largest effect, a majority of companies felt that gas price has had a significant impact on conservation. Of the activities directly sponsored by gas utilities, information-type activities (i.e., advertising and bill stuffers) were indicated to have the greatest impact on conservation, followed by such activities as energy audits, insulation, appliance sales, and rebates.
- A comparison of reduced residential gas use per customer and the increase in real residential gas prices in the 1973-79 period indicates a short-term residential price elasticity of demand of -0.30.
  - On a regional basis, the price elasticity of demand ranged from -0.17 in the West South Central region to -0.59 in the New England region.

It should be noted that the conservation described in this survey and analysis refers to annual average conservation levels only, and should not be implied to represent peak day or seasonal conservation effects. For example, recent developments in January of 1981 in Massachusetts indicate that abnormally cold weather can create peak demands for short periods of a few days, at levels well above the long-term average annual rate of conservation.

C. Background and Methodology

A.G.A.'s special survey questionnaire on gas conservation was sent to 55 companies in all 9 census regions of the U.S., with combined 1979 gas sales accounting for 60% of the gas utility industry. Forty-seven companies responded to the questionnaires for an 86% response rate. These respondents represented some 50% of 1979 gas utility sales. See Appendix A for a sample of the survey questionnaire.

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The survey consisted of the following two parts. Part I contained questions relating to conservation analysis and measurement activities within the gas companies. Information was requested on definition, analytic techniques, factors used in each analysis and level of detail. In addition, quantitative information was requested on the amount of gas conserved to date as a percent decline from 1973 levels in different market sectors and projected gas conservation as a percent decline from 1973 for 1980 and 1990.

Respondents were instructed to provide their best measure of conservation, defined as the percent decline in use per customer compared to a 1973 base use discounting the effect of such factors as weather and changes in economic activity levels. For example, gas consumption per square foot of space or some other unit in the commercial sector may be a more accurate measure of conservation than consumption per commercial customer. Similarly, in the case of the industrial sector, such factors as reduced gas use due to lower levels of industrial activity or reduced gas use due to fuel switching must be discounted when measuring industrial conservation. In the final analysis, respondents defined conservation as a measure of the customer's direct effort to reduce gas consumption at the same level of activity. In the case of the projections of gas conservation in the 1980s, responses were often a best judgment based on trend analysis. The commercial and industrial projections tended to be on the conservative side due to the respondents' sensitivity to the problems mentioned above.

The quantitative section of Part I requested data on conservation for each actual year compared to the 1973 base. The number of useable responses varied by sector for the actual 1974 through 1979 years: the number of responses in the residential sector ranged from 34 for 1974 data to 40 for 1979 data, commercial responses ranged in number from 19 to 24, and industrial responses numbered 8 to 9 (since the industrial customers consumed considerably more gas than residential or commercial customers, fewer responses are needed to produce meaningful results). Responses, in the form of percent declines in gas consumption due to conservation, were averaged for each year to determine the trend in conservation. The sample standard deviation, or the distribution of responses around the mean, appeared to increase over time as the magnitude of conservation increased. For example, in the residential sector, the 34 responses for 1974 showed an average of 6% and a sample standard deviation of ± 3 percentage points around the mean, while the 40 responses for 1979 data showed an average of 15% and a sample standard deviation of ± 5 percentage points from the average. The conservation projections for 1980-1990 showed somewhat greater variance than the actual responses in terms of statistical distribution, however, the trend established in the actual period continued.

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After the effect of weather, the price of gas was found to be the largest influence on residential gas consumption. Since the residential conservation data from the survey discount the effect of weather, these data were used to calculate the price responsiveness of residential gas consumption, or price elasticity. Price elasticity was defined as the percentage change in quantity demanded relative to the percentage change in price ($\Delta Q/Q/\Delta P/P$). Nominal residential gas price data for the nine U.S. census divisions for 1973 through 1979 were obtained from the A.G.A. publication Gas Facts[1]. Inflation effects in the nominal prices were discounted using the GNP price deflator for the 1973-1979 period. Thus, average residential price elasticity was calculated for each region by comparing total real gas price growth with the cumulative six-year decline in gas use.

Part II of the survey requested information concerning gas utility company conservation programs. Questions on corporate policy covered the motivation for promoting conservation, projections for increased activities and the effect of conservation on corporate planning and finance. Questions on corporate activities asked respondents to identify all the various conservation activities and specify those with the greatest impact on customer use. Finally, respondents were asked to indicate the likely impact of various proposed federal and state programs or standards (such as the RCS program, BEPS, and PURPA rate design).

D. Findings: Part I

Table 1 and Figure 1 furnish detailed results from Part I of the survey on a national average basis. The quantitative section in Part I of the survey indicates that in the 6 years following the 1973 oil embargo, gas conservation (the percent decline from the 1973 baseline) has increased nearly every year in all 3 customer classes surveyed in all regions of the U.S., and that for the decade of the 1980s gas conservation is expected to continue to increase annually, but at a slower rate.

In the residential sector, gas use declined due to conservation at a rate of 2.7% per year, resulting in 15% less gas consumption during 1979, relative to the 1973 base. Residential conservation data exhibited reasonable variation from region to region as shown in Table 2. This would be expected given the relative difference between regions for factors such as fuel prices, economic activity, etc. The highest rate of decline in gas consumption was 3.6% per year in the Mountain region and the lowest was 2.0% per year in the

---

1/ Gas Facts (Arlington, Virginia: A.G.A., 1973-1979).

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Table 1

Results of Actual and Projected Gas Conservation[1/]
by Customer Class
(percent decline vs. 1973 base)

	Residential		Commercial	Industrial
	Total Residential	Spaceheating Only		
Actual	% decline	% decline	% decline	% decline
1974	5.7	6.6	4.6	5.9
1975	6.0	7.2	6.8	10.0
1976	8.3	11.2	7.4	10.8
1977	11.8	14.2	11.2	11.5
1978	14.3	18.6	11.9	9.9
1979	14.7	20.4	12.4	8.7
"73-'79 %/yr.	2.7	3.7	2.2	1.5
Projected 1980	16.2	*	12.7 [2/]	10.8
1985	22.5	*	14.2	12.8
1990	25.8	*	16.1	17.5
'80-'90 %/yr.	1.2		0.4	0.8

1/ Refers to the decline in gas consumption per customer discounting the effects of such factors as weather, declines in industrial activity, etc.

2/ Adjusted to reflect the 1979-1985 trend due to a low number of responses.

* Not included in survey.

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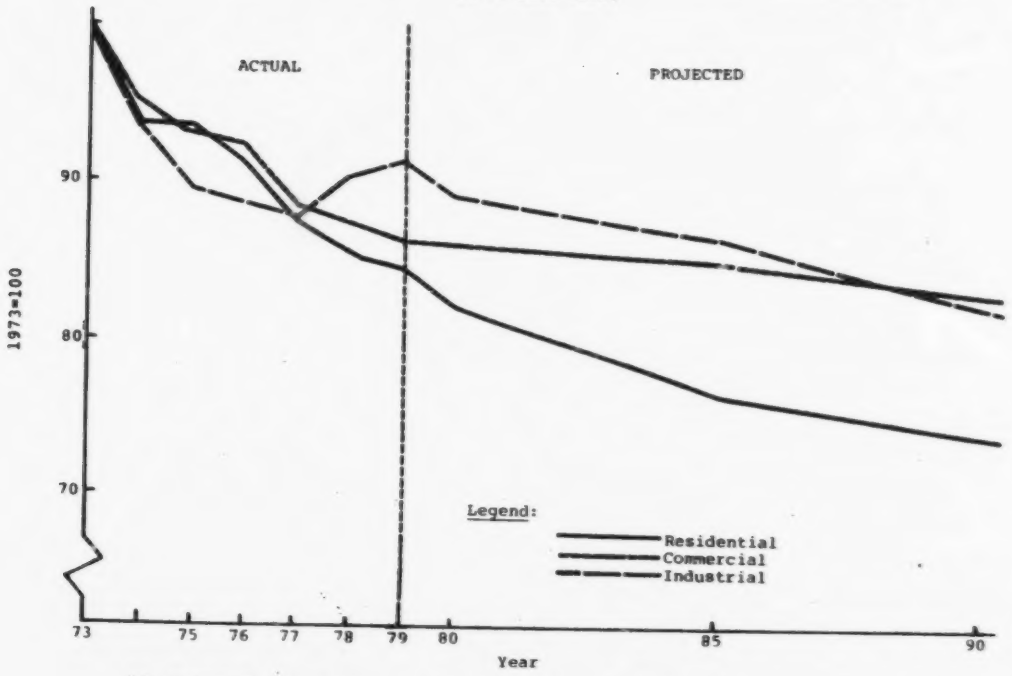
Figure 1

Index of Actual and Projected Conservation[1/] in the Gas Utility Industry
(1973 Base Year)



1/ Refers to the decline in gas consumption per customer discounting the effects of such factors as weather, declines in industrial activity, etc. For example, in 1977 residential, commercial and industrial consumption per customer per degree day was about 12% lower than in 1973 or a conservation index of 88 on a base of 1973=10

Table 2

Residential Conservation and Price Elasticity of Demand (1973-79)

Census Region	Average Annual Rate of Decline (%)	Cumulative 6-year Decline in Gas Use (%)	Total Real Gas Price Growth (%)	Average Residential Price Elasticity
New England	2.5	14.1	23.8	-0.59
Middle Atlantic	2.4	13.6	43.8	-0.31
East North Central	2.7	15.1	53.5	-0.28
West North Central	3.1	17.2	48.2	-0.36
South Atlantic	2.0	11.4	50.3	-0.23
East South Central	N/A	N/A	-	-
West South Central	2.3	13.0	76.8	-0.17
Mountain	3.6	19.7	71.9	-0.27
Pacific	3.4	18.7	39.1	-0.48
Total U.S.	2.7%	14.7%	49.6%	-0.30

Note: There is no clear evidence to explain the differences in elasticities among regions. However, the lower end user prices in the West South Central (WSC) vs. higher prices in New England (NE) could explain why a 76.8% change in price in the WSC could result in only a -0.17 price elasticity while a 23.8% price change in NE could cause a larger -0.59 price elasticity.

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South Atlantic region (see Appendix B for description of census divisions). It should be noted that the regional data are not necessarily reflective of individual company experiences within the region.

Table 2 also contains a comparison on a regional basis of real residential gas price growth and the cumulative decline in gas use over the 1973-79 period. The resulting price elasticities of demand vary across regions from -0.17 in the West South Central census region to -0.59 in the New England census region. The U.S. average residential gas price elasticity of demand was -0.30, i.e., for every 10% increase in the residential gas price, residential gas consumption declined 3% over the 1973-79 period. Gas price elasticities may be lower in the future as opportunities to reduce consumption decrease and become relatively more expensive.

Total residential conservation is projected to grow, primarily on the basis of trend analysis, at a slower rate of 1.2% per year over the 1980-1990 period reaching a level in 1990 of 26% relative to the 1973 base. Table 1 lists both the actual and projected conservation levels as a percent decline versus the 1973 base year for all sectors based on the survey. Figure 1 shows the trend in conservation as an index. For example, residential, commercial and industrial consumption per customer in 1977 (discounted for weather and declines in economic activity) is shown as an index at a level of about 88 vs 100 in the 1973 base year, or a 12% decline in use due to conservation (Fig. 1).

Residential spaceheating use was the one specific end-use application, as opposed to a full sector, for which respondents had sufficient data to report. This is not surprising considering that spaceheating use represents such a significant portion of total residential use per customer, approximately 70%. 2/ Residential gas spaceheating use showed an even greater annual decline due to conservation than total residential gas use over the same 1973-79 period (3.7% per year), with a total decline in 1979 of 20% compared to 1973. The higher conservation figure for gas spaceheating use is most likely a reflection of the fact that baseload consumption, e.g., water heating and cooking, has a more limited conservation capability, whereas spaceheating load can be affected by a variety of measures in the short-run such as thermostat adjustment, weatherization, and insulation. The commercial sector showed lower overall levels of conservation in 1973-79 compared to the residential sector, reaching 12% in 1979; the annual

---

2/ Gas Househeating Survey: 1979, Table 10, (Arlington, VA: American Gas Association, January, 1981).

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rate of decline in consumption was in a similar range -- 2.2%. Commercial conservation is projected to grow at a lower annual rate in the 1980s, approximately 0.4% per year, reaching a level of 16% in 1990 compared to the 1973 base.

Industrial conservation has so far been lower than either the residential or commercial sectors, reaching a level of 9% in 1979, or a decline in use of 1.6% per year through 1979. In the future, industrial conservation is projected to reach a level of 18% by 1990, a decline in use of 0.8% per year through the 1980s.

Also, in Part I respondents were asked whether low cost "primary" energy conservation measures, such as thermostat turn-down, have achieved as much energy savings as possible, and that the customer must move to higher cost "secondary" measures, such as improving the thermal integrity of the building or purchasing more efficient appliances/equipment to achieve further energy savings. Survey respondents generally agreed that additional inexpensive primary conservation is achievable and likely, but that more expensive secondary measures will account for greater shares of gas conservation in the future. This would be at least one major contributing factor why respondents forecasted a slower annual rate of decline in gas consumption for the 1980s compared to the 1973-79 period.

The most important markets cited for conserved gas in 1985 and 1990 followed a regional pattern. Companies in the industrial Midwest tended to focus on the industrial market whereas companies in other regions tended to cite a broader range of markets - including new customers and new end-uses, e.g., cogeneration, air conditioning, and fleet vehicles.

E. Findings: Part II

The findings in Part II of the survey on corporate policies and activities indicate that conservation will play an increasingly important role in the future planning and operations functions of most gas utility companies. The major findings of Part II are:

- Respondents tended to agree on the reasons, if not the order of importance, as to why an active conservation program was important. The most frequently cited reasons were:
  - To ease the burden of higher prices on customers.
  - To support national objectives regarding conservation of non-renewable energy sources.

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- To enhance supplies to meet the needs of existing and new customers, and to allow time for needed new domestic and supplemental supplies to come onstream.

- Most of the responding companies expect their conservation-oriented promotional activities to increase in the future in terms of funds budgeted, personnel involved and customers covered, particularly as a result of government mandated programs such as the RCS program.

- Conservation has affected the operations and planning functions for a majority of companies in the form of:

  - Requiring more frequent rate adjustments.

  - Reducing the load factor.

  - Permitting the deferral of some supply projects (annual or peak).

  - Lowering profitability, primarily because conserved gas is being sold to customers in less profitable rate categories.

- At a minimum, almost all companies rely on conservation-oriented advertising and bill stuffers. Several companies, including those less likely to be entirely compensated for conservation-based load loss, are involved in activities that go beyond the minimum:

  - In designating the factor with the largest effect, a majority of companies felt that gas price had the greatest impact on conservation, followed by information-type activities (i.e., advertising and bill stuffers) and then such activities as energy audits, insulation, appliance sales, and rebate programs.

- There was a general consensus that the major government conservation programs and policies will mean an increased burden for the gas utility companies, while having only a marginal impact on customer conservation. Some of the more frequently observed responses were:

  - Rate design is not an effective conservation activity because customers tend to focus only on their total energy bill, rather than on the specific rate structure. This is particularly true for the small residential and commercial customers.

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- The RCS program will expand most pre-existing programs and will probably require more company funds and personnel than necessary.

- Most companies felt that the proposed Building Energy Performance Standards (BEPS) would have a positive but, minimal impact on their operations.

F. Conclusions

Since the 1973 oil embargo natural gas customers in all market sectors have reduced gas usage levels significantly. In the 1973-79 time period the annual decline in gas use per customer ranged from 2.7% per year in the residential sector, to 2.2% per year in the commercial sector and 1.6% per year in the industrial sector. Most gas utilities believe that, while additional conservation through low-cost measures is likely, the annual rate of decline in gas consumption will slow down in the decade of the 1980s since a large share of future conservation will have to come through more expensive, time consuming measures.

As low-cost conservation measures are exhausted, the price of conservation will also increase. Gas utility companies recognize the need to assist customers in meeting their energy bills and expect conservation-oriented promotional activities to increase even more in the future. Fede-al or state programs designed to assist consumers must consider the costs of these programs compared to the amount of energy likely to be conserved. The most effective government programs will be those that complement the already existing and well-functioning conservation market place rather than duplicate it. In particular, new rate designs such as proposed by DOE for PURPA with the intent of promoting conservation should be avoided as counterproductive since the results of this survey indicate that significant levels of conservation have already occurred and are expected to continue under the current rate structure.

The cumulative effect of a continued decline in gas consumption per customer each year means that gas utilities will look to both traditional and new markets for this conserved gas. Local conditions will dictate in the future whether companies will look to the industrial market or new markets. However, Fuel Use Act restrictions, incremental pricing and other market constraints could pose significant barriers.

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8/28/80

Respondent's Name_____

Phone No._____

Company Name_____

APPENDIX A

GAS UTILITY CONSERVATION SURVEY

Part I Conservation Activities

A. Definition

1. How does your company define conservation?

   a) Any reduction in consumption per customer not explained by weather_____

   b) Other (explain)_____

   _____

2. Which sectors have you studied?_____

   _____

3. a) Have you attempted to measure conservation by end-use in any sector?_____

   _____

   b) If yes, are your studies based on:

      1. sales data for an entire customer class_____

      2. data from a sample of customers_____

      3. data on individual customers_____

      4. other (explain)_____

4. When did you begin analytic activities aimed at measuring conservation?_____

B. Results

1. a) Do you have quantitative results on the amount of conservation experienced since the 1973 oil embargo?

   Yes___ No___

   b) If yes, can you provide your measure of conservation as the percent of variation from the 1973 baseline for each year (normalized for weather variation)?

	Residential	Commercial	Industrial
1974			
1975			
1976			
1977			
1978			
1979			

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Can you measure conservation by end-use (e.g., space heat, cooking, process, etc.) for each sector?

	Residential	Commercial	Industrial
1974			
1975			
1976			
1977			
1978			
1979			

c) Please explain any significant conservation prior to 1973

_____

2. a) Do you have projections of conservation, by sector, through 1990 (defined as % reduction from 1973 or other specified base)?

	Residential	Commercial	Industrial
1980			
1985			
1990			

b) How did you arrive at these projections?

1. Judgment _____
2. Strict trend analysis _____
3. Trend analysis tempered by judgment _____
4. Detailed quantitative analysis _____
5. Projections by others _____
6. Other (explain) _____

c) If a quantitative analysis was performed, which of the following factors were explicitly included in the quantitative analysis? Please rank their importance in affecting the results of the analysis.

Factor	Included in Analysis (Yes,No)	Rank (1,2,3...)
Past Trends		
Average Price of Gas		
Rate Design		
Appliance Replacement		
New Technologies		
a. Appliances		
b. HVAC		
c. Industrial Process		
d. Solar		
Building Codes		
Building Replacement		
Other: _____		

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d) At what level of detail are industrial conservation projections developed?

1. All customers as a class_____
2. SIC code_____
3. Individual customers_____
4. End-use (e.g., space heat, process, etc.)_____

_____

e) Does the method for analysis of commercial conservation differ from that for residential customers? Yes___ No___

If so, how? _____

_____

_____

3. There is evidence to suggest that low cost "primary" energy conservation measures, such as thermostat turn-down, have achieved as much energy savings as possible, and that the customer must move to higher cost "secondary" measures, such as improving the thermal integrity of the building or purchasing more efficient appliances/equipment, to achieve further energy savings.

a) Do you believe this is true? Explain, e.g., whether additional thermostat turn-down is achievable. _____

_____

b) What changes in customer consumption patterns particularly affect conservation in your area? _____

_____

In the residential/commerical sector? _____

_____

In the industrial sector? _____

_____

4. Since 1973 what has been done with conserved gas?

a) Please indicate volumes or percentages of conserved gas;

1) Sold to new residential customers _____
2) Sold to new commercial customers _____
3) Sold to new industrial customers _____
4) Sold to existing industrial customers _____

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5) Sold to meet demand from conversion customers _____

6) Put into storage _____

7) Other _____

b) Is conserved gas displacing oil? _____

c) What will be the most important markets for conserved gas in 1985 and 1990? _____

Part II Conservation Programs

A. Corporate Policy

1. Apart from any mandatory Federal or State programs, does your company actively promote conservation as a matter of policy? _____ If not, why? _____

_____

2. a) Please list, in order of importance, the reasons why an active conservation program is important to your company:

1. _____

2. _____

3. _____

4. _____

5. _____

b) Will these reasons have a different order of importance five years from now? _____

_____

c) What criteria do you use to judge program effectiveness?

_____

3. Are your company's conservation activities expected to increase? If yes, describe how (budget, personnel, number of customers covered, etc.) _____

_____

4. How has conservation affected:

a) Your need for rate adjustments:

No Affect _____
More Frequent _____
Less Frequent _____

b) Your company load factor?

No Affect _____
Deteriorated _____
Improved _____

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c) Planning for annual supply projects?

No Affect _____
Deferred _____
Other _____

d) Planning for peak-day projects?

No Affect _____
Deferred _____
Accelerated _____

5. Has conservation hurt your company profits? If so, please rank the reasons for the loss of profitability.

Cause	Rank (1,2,3...)
Lag in rate adjustments	_____
Conserved gas has been sold to customers under less profitable rates	_____
Take-or-pay contracts with suppliers	_____
Increased cost of service for new customers using significantly less gas	_____
other: _____	

B. Corporate Activities

1. Please indicate which of the activities below are part of your conservation program:

Activity	Sector or Sectors Covered (i.e., residential, commercial, industrial)	Level of Participation (i.e., direct, subsidiary, referral to other companies)
Energy Audits	_____	_____
Appliance Sales	_____	_____
Financing	_____	_____
Advertising	_____	_____
Bill Stuffers	_____	_____
Insulation	_____	_____
R&D in improved equipment	_____	_____
R&D in improved industrial processes	_____	_____
Conservation home awards	_____	_____
E-cube services	_____	_____
Hot line	_____	_____
Literature	_____	_____
Furnace/equipment tune-up	_____	_____
Other:	_____	_____

2. Which activities have had the greatest impact on conservation (please rank at least 3)? _____

_____

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3. Do you view rate design, as opposed to overall rate level, as a conservation activity? _____

_____

C. Federal/State Programs

1. a) How will the Residential Conservation Service (RCS) program affect your existing conservation programs? _____

_____

b) Did you have significant objections to the RCS program?

_____

2. a) Does your state now require that new buildings meet energy conservation standards? Explain _____

_____

b) Do you believe that the proposed Building Energy Performance Standards (or similar Federal legislation) will have a significant impact on your company? _____

_____

3. Do you feel that it is necessary in terms of regulatory or public policy measures to promote conservation? _____

_____

D. Additional Comments

_____

_____

_____

_____

_____

Thank you.

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APPENDIX B

Census Divisions and Corresponding States

New England (NE)

- Connecticut
- Maine
- Massachusetts
- New Hampshire
- Rhode Island
- Vermont

Middle Atlantic (MA)

- New Jersey
- New York
- Pennsylvania

East North Central (ENC)

- Illinois
- Indiana
- Michigan
- Ohio
- Wisconsin

West North Central (WNC)

- Iowa
- Kansas
- Minnesota
- Missouri
- Nebraska
- North Dakota
- South Dakota

South Atlantic (SA)

- Delaware
- District of Columbia
- Florida
- Georgia
- Maryland
- North Carolina
- South Carolina
- Virginia
- West Virginia

East South Central (ESC)

- Alabama
- Kentucky
- Mississippi
- Tennessee

West South Central (WSC)

- Arkansas
- Louisiana
- Oklahoma
- Texas

Mountain (M)

- Arizona
- Colorado
- Idaho
- Montana
- Nevada
- N. Mexico
- Utah
- Wyoming

Pacific (P)

- Alaska
- California
- Hawaii
- Oregon
- Washington

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ENERGY ANALYSIS

American Gas Association

Policy Evaluation & Analysis Group
American Gas Association
1515 Wilson Boulevard
Arlington, VA 22209
703 841-8400

1981-11 September 18, 1981

COMPARISON OF RECENT LONG-RANGE U.S. ENERGY FORECASTS: 1981 UPDATE

A. Introduction

Future U.S. energy supply and demand is a matter of major public interest and several publicly available energy forecasts are prepared each year by government, industry and academic groups. These studies employ a variety of assumptions, value judgments and methods. The resulting projections, taken as a group, can be useful in bounding a probable or consensus range of future U.S. energy requirements as currently viewed by energy forecasters. However, as the current energy situation changes, the consensus outlook for the future energy situation also changes.

The purpose of this analysis is to review the most prominent recent projections of total primary energy consumption to the year 2000, to summarize the current consensus regarding future U.S. energy production and consumption, with a special emphasis on natural gas, and to compare these projections with those published a year ago, which were the subject of an earlier A.G.A. analysis.[1]

B. Executive Summary of Major Conclusions

- Current energy studies predict that energy consumption will lie generally in the range of 90-110 quadrillion Btu's by the year 2000 (the cross-hatched area in Figure 1), compared to 76.2 quads in 1980. This projection range is significantly lower than the 100-125 quads predicted by studies published in the late 1970s.

- The gas portion of total projected energy consumption in the year 2000 averages between 17% and 27% (or 17-24 quads) in the current group of forecasts. The gas share in 1980 was approximately 27%, or 21 quads. Earlier studies had projected the gas share to be considerably lower, between 12% and 22% of total projected primary energy consumption.

- The current gas forecasts are generally more optimistic than previous forecasts because of a more favorable outlook for gas supplies (including conventional resources, development

1981 by the American Gas Association.

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of tight formations, coal gasification, and unconventional and other synthetic gas resources) and the anticipated importance of non-traditional gas uses such as gas-fired cogeneration.

- If national security, environmental quality or other factors act to inhibit the use of other fuels, the gas share could be required to be even greater -- possibly returning to the 33% level of the early 1970s. In this case, a gas supply of 33 quads or more could be required by 2000.

C. Discussion of Seven Recent Energy Studies

Following are summaries of the seven studies compared in this analysis.

- U.S. Department of Energy, Energy Projections to the Year 2000: A Supplement to the National Energy Policy Plan Required by Title VII of the U.S. Department of Energy Organization Act (Public Law 95-91), July 1981.

  This forecast, referred to hereafter as NEPP (National Energy Policy Plan), was produced with the aid of an integrated system of computer models of energy supply and demand. It considers energy consumption under three oil price trajectories ($45, $64 or $86 per barrel in constant 1980 dollars in the year 2000) and three different rates of economic growth. Projected energy consumption ranges between 90 quads (corresponding to a 2% annual growth in real GNP) and 110 quads (corresponding to a 3% GNP growth rate). The projected energy/GNP ratio is approximately 23.2 quads per trillion dollars of real GNP ($1980) in all three cases. The year 2000 gas supply range is 18-25 quads, depending on assumptions regarding the geologic resource base for conventional gas, and development of synthetic and unconventional gas supplies. By comparison, last year's National Energy Plan II forecasted total energy consumption of 117-123 quads and gas supply of 18-24 quads in the year 2000.

- U.S. Energy Information Administration, 1980 Annual Report to Congress, March 1981.

  Like NEPP, the EIA forecast was derived with the aid of computer models of energy supply and demand. It examines energy consumption patterns under three alternative oil price trajectories ($45, $64 and $100 per barrel in $1980 in the year 2000). The high oil price case leads to 97 quads of

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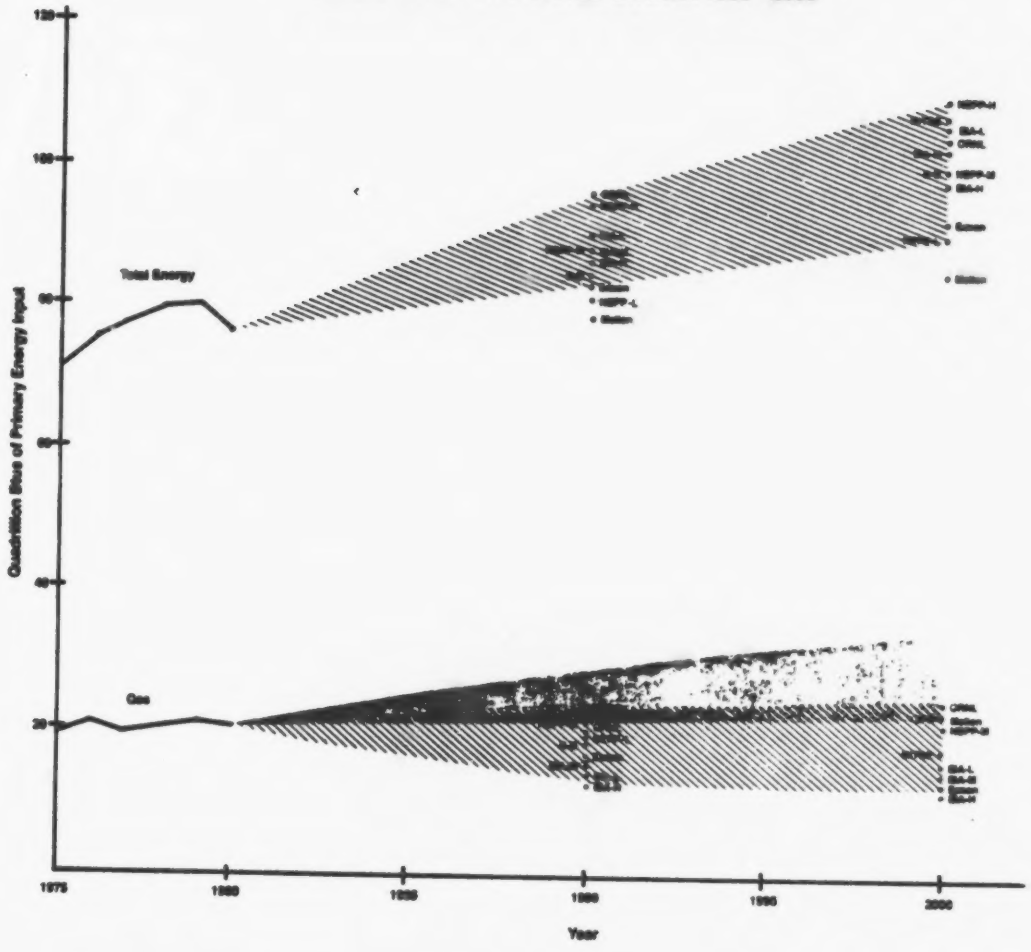
FIGURE 1
ALTERNATIVE PROJECTIONS OF PRIMARY ENERGY CONSUMPTION IN THE UNITED STATES: 1980 - 2000



Legend:
- General range of forecasts of seven studies
- Total gas demand accounting 25-28% market share

B-D—Bahr-Davenport
EIA—Energy Information Administration
- EIA-H—High Price Case
- EIA-M—Mid Price Case
- EIA-L—Low Price Case

Exxon—Exxon Company USA
Mellon—Energy Productivity Center of the Mellon Institute
MITRE—The MITRE Corporation
NEPP—National Energy Policy Plan U.S. Department of Energy
- NEPP-H—High Economic Growth Case (3% GNP growth)
- NEPP-M—Medium Economic Growth Case (2.5% GNP growth)
- NEPP-L—Low Economic Growth Case (2% GNP growth)

ORNL—Oak Ridge National Laboratory
- Low Demand High Domestic Supply Case

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total energy consumption in 2000, while a low oil price assumption raises consumption to 107 quads. The energy/GNP ratio ranges from 22.5 in the high price case to 24.9 in the low price case. The projected gas share is only around 17% because of an assumption that prohibitions against future gas use in power plants and industrial boilers, which are contained in the Power Plant and Industrial Fuel Use Act and other legislation, will be strictly enforced. This assumption produces the result that gas supplies are greater with low oil prices than with high prices. EIA explains this result by noting that gas supply projections are constrained by demand and that "more gas could be produced if needed".[2/]

- Exxon Company, U.S.A., Energy Outlook, 1980-2000, December 1980.

  Exxon predicts a strong decline in energy use per unit of output (only 21.0 quads per trillion dollars of output measured in constant 1980 dollars) and forecasts only 92 quads of energy consumption in 2000. This is the second lowest forecast of all the studies analyzed. Exxon is also the most pessimistic of all the studies regarding the outlook for gas, with gas providing only 17 quads (less than 19% of total energy) in the year 2000. It foresees a substantial decline in both conventional and unconventional domestic production, lower gas use by electric utilities and a shift from gas to electricity in the residential and commercial sectors.

- Mellon Institute, Energy Productivity Center, A Strategic Look at Energy Markets 1980-2000: The Least-Cost Energy Strategy Revisited, Spring 1981.

  The Mellon Institute's analysis is the result of a technical evaluation of the fuel mix and energy consumption level that would minimize the cost of energy service over the next two decades. "Least cost" strategies involve significant investment in energy conservation technologies. The "least cost" primary energy consumption for the year 2000 is calculated to be 84.7 quads, 27% of which is gas. Gas-fired cogeneration accounts for over 4 quads of the year 2000 least cost energy consumption.

- The MITRE Corporation, U.S. Energy Strategies: Some Options for Eliminating Oil Imports by the Year 2000, April 1981.

  This study evaluates technical options for eliminating oil imports by the year 2000. It concludes that "liquid fuels are the only critical domestic energy resource in the year 2000" and therefore does not deal with non-liquid

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fuels in any detail. It produces a baseline forecast (based on EIA's mid-price scenario), of 107 quads of total energy consumption, and evaluates liquid fuel supply options under a "reasonable choices" scenario and a "technically feasible" scenario. Since the focus of the study is on liquid fuels, the outlook for gas supplies is not well defined; however, the gas supplies are forecasted to range as high as 36 quads based on "estimated potential from recent findings."[3]

- Peter G. Behr and Stephen T. Davenport, Bechtel Corporation, "New Pipeline Prospects Projected in U.S. and Canada for 1981-2000," Oil and Gas Journal, June 15, 1981.[4] The Behr-Davenport forecast is a demand-based "most likely case" evaluation of future energy supply and demand which was used as the basis for a corporate forecast of pipeline construction needs. Their total energy projection is 100 quads, of which nearly 23% is gas. Almost three quads of synthetic gas from coal is projected for the year 2000. No explicit assumptions regarding oil prices or GNP growth were given in this forecast report.

- Oak Ridge National Laboratory, Toward a Desirable Energy Future: A National Perspective, March 1981.

  This study evaluates strategies intended to reduce U.S. vulnerability to disruptions in world oil supplies. Like the Mellon and MITRE studies, ORNL takes a technological approach to reducing import dependence, identifying feasible energy supply and conservation options. They characterize their projections as a definition of a desirable future rather than a forecast of a probable future. In that context, they have identified two extreme cases -- a "Low Demand-High Domestic Supply Case" and, conversely, a "High Demand-Low Domestic Supply Case." Energy consumption requirements for the two cases are 103.7 quads (23% gas share) and 126.9 quads (18% gas share), respectively. The "High Demand" case is not strictly comparable to the other studies presented here in that it assumes virtually no decline in the energy/GNP ratio for the rest of the century. Therefore, the projection of 126.9 quads may be considered to be an "outlier" -- outside the range of consensus across all the forecasts.

D. Comparison of Forecasts

Forecasting Methodologies

Two basic categories of forecasts may be readily identified from the seven presented here. One category includes the NEPP, EIA and Exxon studies, which are quantitative evaluations of future outcomes

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based on present trends in energy supply and consumption. These studies generally take a similar approach to forecasting energy supply and demand as functions of economic growth, energy prices, the energy/GNP ratio, geology, technology and energy policy.

First, a certain growth rate for GNP is assumed, based on the expected future price of oil and other economic factors. Next, a number of calculations or computer simulations may take place, which implicitly apply an energy/GNP ratio to the GNP forecast to derive an estimate of energy demand that is consistent with the GNP forecast.[5/] Various additional assumptions and calculations regarding the geologic availability of specific fuels and future policy decisions are then invoked to estimate the future supply and supply prices of various fuels. Final market prices and quantities are determined by the interaction of supply and demand.

A second type of forecast is typified by the Mellon, MITRE and ORNL studies, which seek strategies to achieve socially desirable goals articulated by the authors of the studies. In the case of the MITRE and ORNL studies, the objective is to minimize oil imports. In the case of the Mellon study, the objective is to achieve a "least cost" mix of fuel use and energy conservation technologies.

While the Behr-Davenport forecast fits neither of these categories precisely, it illustrates the development and application of an energy forecast for purposes of corporate or industry planning.

Forecast Assumptions

A remarkable degree of consensus exists among the forecasts. Forecast assumptions are shown in Table 1. Economic growth assumptions in most cases are 2.5% per year between 1980 and 2000. This represents a more pessimistic assessment of economic growth than had been assumed in previous forecasts, and generally correspond to lower levels of energy consumption. The two studies which assume higher GNP growth (ORNL and the NEPP High GNP Case) forecast the highest levels of energy consumption.

In part, the lower economic growth projections reflect the effects of higher oil prices assumed to prevail throughout the forecast period. The doubling of oil prices in 1980 has led forecasters to lower their economic growth projections and to reduce their projected energy/GNP ratios. The EIA and DOE oil price assumptions are almost identical. Oil prices are assumed to be as high as $100 per barrel by the year 2000 or as low as $45 (in constant 1980 dollars) and are varied across a high price scenario, a middle price scenario and a low price scenario to assess the effects of oil prices on energy supply and demand. MITRE's oil price assumption is consistent with EIA's middle oil price tra-

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Table 1

ECONOMIC GROWTH AND OIL PRICE ASSUMPTIONS OF SEVEN RECENT ENERGY STUDIES[1/]

	Behr-Davenport	EIA	Exxon	Mellon	MITRE	NEPP	ORNL
Annual Economic Growth Rate (%)	NA	2.5	2.6	2.5	2.5	3.0 (high) 2.5 (mid) 2.0 (low)	2.9
World Oil Price (Constant $1980 per barrel)							
1990	NA	$ 53 (high) 44 (mid) 34 (low)	$46	NA	NA	$62 (high) 47 (mid) 37 (low)	NA
2000	NA	$100 (high) 64 (mid) 45 (low)	$56	NA	$72	$86 (high) 64 (mid) 45 (low)	NA

1/ See Bibliography of Energy Studies Analyzed, p.14.

NA = Not available

jectory, and Exxon's lies between EIA's low and middle price trajectories. (The Mellon, ORNL and Behr-Davenport forecasts made no explicit oil price assumption.)

Forecast Results

In view of the similarities in assumptions it is not surprising to find little variation in the forecast results shown in Table 2. A simple statistical analysis of these results narrows the range of forecasted total energy consumption even more to approximately 90-110 quads. This range is arrived at as follows:

1. Taking a simple average over all the scenarios (including the range of 90-110 quads forecasted by NEPP and the 126.9 quads forecasted in the ORNL High Demand case) gives an average projected energy consumption of 101.7 quads with a standard deviation of 10.9 quads. This imples a range of 90.8-112.6 quads of primary energy consumption in the year 2000.

2. If the sample is restricted to those scenarios which assume a 2.5% GNP growth rate, the average is 98.6 quads with a standard deviation of 8.1 quads. This implies a range of 90.5-106.7 quads.

3. Alternatively, eliminating the two extreme points across all the forecasts (84.7 and 126.9) gives a range of 90-110 quads.

Thus, 90-110 quads appears to represent a reasonable range of forecasts of primary energy consumption in the U.S. for the year 2000.

The energy conservation implicit in these studies is reflected in the calculated energy/GNP ratios for the year 2000 shown in Table 2. These range from 19.7 quads per trillion dollars of real GNP (expressed in $1980) in the Exxon forecast to 24.9 in the MITRE study, compared to an actual 1980 ratio of 29.0. As for the predicted fuel mix, dramatic increases in nuclear and coal use from present levels are common to all forecasts, while a substantial decline in oil consumption is expected. While the degree of change in demand for these fuels varies somewhat across the studies, the possibility that oil consumption could decline by 25%-30% by the end of the century (as predicted by all but two of the studies) has serious implications for the U.S. petroleum refining industry. Analysis of these implications is, however, outside the scope of this paper.

The outlook for gas, shown in Table 3, is even less clear-cut than for other fuels. The NEPP, Mellon, ORNL and Behr-Davenport studies predict that gas use in 2000 will equal or exceed current levels. EIA, Exxon and MITRE's baseline, on the other hand, predict declining gas use.

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Table 2

DETAIL OF ALTERNATIVE PROJECTIONS BY PRIMARY ENERGY FORM OF U.S. ENERGY CONSUMPTION IN THE YEAR 2000[1/]

Primary Energy Consumption (quadrillion Btu's)	1980 Actual[2/]	Behr-Davenport	EIA Mid	Exxon	Mellon	MITRE	NEPP	ORNL Low Demand/ High Supply
Total	76.2	99.6	102.5[3/]	92.2	84.7	106.9	100[6/]	103.7
Gas	20.5	22.6	17.6[4/]	17.2	22.6	18.6[5/]	21.4[7/]	24.0
Oil	34.2	26.1	26.5	31.0	25.3	30.7	23	27.7
(oil imports)	(13.4)	(1.6)	(4.6)	(9.5)		(11.0)	(3)	(1.5)
Coal	15.6	33.9	36.7	28.6	27.7	34.7	34.7	32.2
Nuclear	2.7	10.5	11.1	9.9		11.9	10.6	17.6
Other	3.2	6.5	10.6	5.5	9.1	11.0	9.7	2.2
Indicated Energy GNP Ratio (quads per trillion $1980)	29.0	NA	23.7	21.0	19.7	24.9	23.2	23.1
Indicated Gas Share (%)	26.9	22.7	17.2	18.7	26.7	17.4	21.4	23.1

1/ See Bibliography of Energy Studies Analyzed, p. 14.
2/ Source: Energy Information Administration, Monthly Energy Review (Washington, DC: Government Printing Office, August 1981), p. 6.
3/ Range 97.2-106.6
4/ Range 16.4-17.9
5/ Range 16-36
6/ Range 90-110 for GNP growth rates of 2.0%-3.0%
7/ Range 18-25 depending on geology and technology assumptions

Note: Numbers may not add up to totals due to rounding.

NA = Not Available

Table 3

ALTERNATIVE PROJECTIONS OF U.S. GAS SUPPLY FOR THE YEAR 2000
(Quads)

	1980 Actual[1]	Behr-Davenport	EIA Mid	Exxon	Mellon	MITRE	NEPP	ORNL Low Demand/ High Supply
Conventional								
Lower 48	19.7	15.3	10.7	NA	NA	NA	13.9	NA
Alaska	-	1.8	1.3	NA	NA	NA	0.8	NA
Subtotal	19.7	17.2	12.0	14.4	NA	NA	14.7	17.1
Unconventional	-	NA	4.7	NA	NA	NA	3.2	NA
Synthetic	-[2]	2.9	0.3	1.7	NA	NA	1.4	6.3
Total Domestic Supply	19.5	20.1	17.0	16.1	NA	18.6	19.4	23.4
Imports	1.0	2.6	0.6	1.0	NA	0	2.0	0.6
Total Supply	20.7	22.6	17.6	17.2	NA	18.6[3]	21.4[4]	24.0

1/ Source: Energy Information Administration, Monthly Energy Review (Washington, DC: U.S. Government Printing Office, August 1981) p. 50.
2/ Approximately 0.1 quad of synthetic gas produced in 1980 is classified by EIA according to feedstock (oil or coal)
3/ Range 16-36
4/ Range 18-25

Note: Numbers may not add to totals due to rounding.

NA = Not Available

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Overall, the range of gas share predictions in this group of studies is substantially higher than in earlier forecasts. The group of studies surveyed in 1980 predicted a 12%-22% gas share in 2000, compared to a 17%-27% range across the current forecasts. This change is partly due to a more favorable outlook for gas supplies. Recent discoveries of conventional gas resources were noted by MITRE as indicative of a much larger geologic resource base than had been assumed by earlier forecasts. Greater optimism regarding gas production from unconventional sources (such as tight sands, Devonian shale, and geopressured methane) and from synthetics (e.g., high-Btu coal gasification) is another factor. In the Mellon least-cost energy strategy, gas-fired cogeneration plays a significant role. Finally, the lower growth in energy consumption contained in this group of forecasts results in a higher relative share for gas.

The more optimistic of the gas share forecasts are consistent with a continuation of the recent gas share of more than 25%. If gas is to maintain this contribution to total U.S. energy consumption, gas supplies in the range of 22-27 quads will be required by the year 2000 (based on total energy requirements of 90-110 quads). In addition, the national interest may dictate even higher gas consumption out of consideration for national security, environmental quality and other factors. In this case, gas' market share could return to the 33% level experienced during the early 1970s, resulting in a gas supply requirement of 33 quads or higher.

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Table 4

CONSUMPTION OF NATURAL GAS AND TOTAL PRIMARY ENERGY

1966 - 1980

Year	Natural Gas Consumption (Quads)	Total Primary Energy Consumption (Quads)	Gas Market Share (Percent)
1966	17.4	56.9	30
1967	18.2	58.3	31
1968	19.6	61.8	32
1969	21.0	65.0	32
1970	22.0	67.1	33
1971	22.5	68.3	33
1972	22.7	71.6	32
1973	22.5	74.6	30
1974	21.7	72.8	30
1975	19.9	70.7	28
1976	20.3	74.5	27
1977	19.9	76.4	26
1978	20.0	78.2	26
1979	20.5	78.8	26
1980	20.5	76.2	27

Sources: 1966 - 1972 - American Gas Association, Historical Statistics of the Gas Utility Industry 1966 - 1975 (Arlington, VA: American Gas Association, 1977), p. 66.

1973 - 1980 - Energy Information Administration, Monthly Energy Review, July 1981 (Washington, DC: U.S. Government Printing Office, July 1981), p. 6.

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FOOTNOTES

1/ American Gas Association, Comparison of Recent Long-Range U.S. Energy Forecasts, Energy Analysis 1980-9, August 22, 1980.

2/ EIA, 1980 Annual Report to Congress, Volume III, page 172.

3/ The MITRE Corporation, U.S. Energy Strategies: Some Options for Eliminating Oil Imports by the Year 2000, April 1981, page 13.

4/ The authors of this forecast state in the article that they "would not want to title it a 'Bechtel' forecast" (page 80). Therefore, it will be referred to herein as the "Behr-Davenport" forecast.

5/ The energy/GNP ratio is inherent in the assumptions regarding demand elasticities, industrial fuel use, energy policies, energy conservation efforts, and future energy prices -- all of which are involoved in estimating energy required to produce the forecasted level of GNP.

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American Gas Association

1515 Wilson Boulevard Arlington, Va. 22209
Telephone 703 841 8400

December 18, 1981

Mr. Ralph D. Fleming
U.S. Department of Energy
CE-131.2
Washington, DC 20585

Dear Mr. Fleming:

The American Gas Association appreciates the opportunity to review the "Coordination Draft" prepared by Aerospace Corporation concerning their "Assessment of Methane, Natural Gas and Synthetic Natural Gas for Automotive Vehicles." We understand the document under review is the draft of the Executive Summary - one of three volumes constituting the Department of Energy, Office of Vehicle and Engine R&D review of natural gas powered vehicles. A.G.A. commented on the body of the Report (previously entitled "Assessment of Natural Gas Application to Automotive Vehicles") in a letter dated October 2, 1981. We presume that the "Coordination Draft" (or Summary) reflects the most current conclusions to be reported in the Report body and will provide our comments with that understanding.

In general, A.G.A. feels that the summary has some very positive statements to make about the advantages of natural gas powered vehicles. Ralph, you will recall that A.G.A. called for DOE endorsement of natural gas powered vehicles at the recent hearings, conducted by the House Subcommittee on Transportation, Aviation and Materials and chaired by Representative Dan Glickman. Following that hearing, Mr. Stadler approached us with the idea of a DOE endorsement in some yet to be determined form. We would, of course, enjoy meeting with DOE to further discuss this matter. I mentioned this because this summary represents an opportunity for DOE to portray natural gas powered vehicles in a positive fashion, and in effect, take a step towards an endorsement of these vehicles.

We recommend that you carefully review the summary with a critical eye toward the statements made concerning natural gas powered vehicles and the comparative language that the Abstract and Highlights presents. For example, the Foreward states "methanol is included in this study for comparison purposes because it is an alternative liquid fuel producible from the same resources as methane." This statement would imply to the technically uninformed reader that methane has to be synthetically produced for automotive fuel purposes in parallel fashion as required for methanol. This is obviously misleading because methane/natural gas is available

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and used directly as a fuel - no process conversion is required. Methanol supplies, conversely, are either presently imported or produced synthetically from natural gas (Table 8, page 18). We suggest the referenced sentence be truncated after the phrase "alternative liquid fuel." Alternately, the phrase "were it required to be synthetically produced" could be added following the word "methane."

The Abstract illustrates an editorial weakness common to the volume. In general, Aerospace deemphasizes the advantages of natural gas and emphasizes the advantages of methanol. It is technically incorrect and editorially unwise for DOE to accept this bias. For example, methanol is purported to be included by Aerospace so that comparative conclusions can be drawn. The bias against natural gas is evident in the paragraphs addressing equipment/systems, energy efficiency and supply issues. Arguably, methanol shouldn't be addressed in the Abstract at all since it is present in the report for comparative purposes only. However, if you, Ralph, feel that methanol must be mentioned then we would recommend that certain editorial changes be directed to your contractor. The existing language reads:

> "Over 275,000 Italian and 20,000 domestic vehicles presently use NG. Conversion kits are commercially available for spark-ignition engines, but not for diesels. A typical car conversion costs $1200 to $2000, adds 175 to 300 pounds, and provides a driving range of 60 to 120 miles on compressed natural gas (CNG) or 200 to 400 miles on cryogenic liquified natural gas (LNG). Both require special fueling facilities and vehicle tanks. Methanol is a well-proved spark-ignition engine fuel."

A.G.A. proposes better comparative language to read:

> Over 275,000 Italian and 20,000 domestic vehicles presently use NG. Conversion kits allow the vehicle to operate in dual-fuel modes, i.e. natural gas in addition to gasoline, and, are commercially available for spark-ignition engines, but not for diesels. A typical car conversion using existing technology costs $1200 to $2000 and adds 175 to 300 pounds to the vehicle weight; a driving range of 60 to 120 miles on compressed natural gas (CNG) or 200 to 400 miles on cryogenic liquefied natural gas (LNG) can be expected. The driving range for gasoline is unchanged. Both require special fueling facilities and vehicle tanks.
>
> Methanol as a motive fuel does not supplement the normal gasoline system but rather replaces it. Conversion kits to accomplish this are not commercially available, and relatively little commercial on-the-road experience exists as compared

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to NG(natural gas). The fuel system must be modified to account for the corrosive effects of methanol. Conversion costs typically range from _____ to _____. There is no significant effect on vehicle weight; driving range or fuel economy is approximately halved. (Aerospace Corporation should provide the conversion costs).

Energy efficiency and technological advances are addressed in the third paragraph. The sentence referring to 6.5 billion GPY needs clarification. Since gasoline savings using advanced technology are stated for methanol, why not state the comparative savings with advance technology concepts for natural gas? Secondly, supply and cost projections for natural gas are given. We disagree that supply projections and user economics are "very uncertain." In no case are they less uncertain than for methanol where conversion kits are not commercially available and the majority of methanol supply is expected to be either imported (Table 10) or converted from natural gas. Indeed the Draft at page 17 concludes that methanol availability estimates "are even more uncertain than for NG." Lastly, we feel that methanol costs should be presented in the Abstract. The data in Table 9, page 17, are illuminating. Methanol produced from natural gas is more than twice the comparable CNG fuel cost.

The comments presented heretofore have concentrated on editorial style. A.G.A. feels it is in DOE's interest to remove the contractor bias. Several of the technical comments following will underscore this theme. The Summary states (p.xv), "... production of methanol from coal or wood is about as efficient as production of methanol from NG(natural gas)." The words "about as efficient" cover many methanol inefficiencies. It should be apparent that production of methanol from natural gas is more efficient than the production of methanol from coal. Secondly, there is no need to burden or mislead natural gas energy efficiency findings with comparisons of methanol or CNG produced from coal or wood. Compressed natural gas is 1.56 times more efficient than methanol produced from coal (Table 11, Logistic Chain Efficiency from Resource to Vehicle Input). This should be reported along with the almost 2 to 1 cost advantage for CNG over methanol (Table 9, U.S. Energy Prices: History and Projections). Combined, these advantages for natural gas over methanol are compelling. Rather than making this point, however, the reader is treated to an irrelevant assessment of methanol production.

A second technical point concerns the supply of methane. Table 8 clearly shows that the production of methanol from natural gas and petroluem products will have to increase roughly 80 percent (1770+110/1060=1.77) to satisfy

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traditional methane markets (including the 110 million gallons per year already consumed in developing markets). Any growth in developing methanol markets i.e. transportation fuel for vehicles, would necessarily be served through 1990 by imports because of the lead time required to build coal-based methanol plants. Therefore, the Summary should indicate that the creation of a transportation market for methanol would be supplied from imports, and, that these imports would be substituting for less expensive and more efficient gasoline.

Lastly, Table 12 and 13, which address vehicle characteristics and resource consumption , should include data for an optimized single fuel natural gas vehicle. The Highlights (p.xv) make these statements:

> "An SI (spark-ignition) engine fully optimized for NG operation is more efficient than its gasoline counterpart (p. xiv).
>
> "...with an optimized design, energy efficiency gains of 20 percent or more are projected." (p.xiv)
>
> "Only CNG produced from NG has a logistic chain efficiency comparable to that of gasoline or diesel fuel" (p.xv)

We recommend that the contractor include the single fuel data in these tables because it represents an advanced technological opportunity consistent with the objectives of the Report and the view taken of methanol.

In conclusion we feel that with DOE guidance, this Summary and its accompanying volumes could make a significant contribution to the knowledge concerning this rapidly expanding transportation system. We appreciate the opportunity to provide our comments.

Sincerely,

Randall I. Cole

Randall I. Cole
Manager
Government Relations

cc:

Mr. Henry Stadler

RC/rr

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BEECH
alternative
energy
DIVISION

P.O. Box 85
Wichita, Kansas 67201

Cable Address "Beechcraft"
Telex No. 417-422

October 2, 1981

Dr. Ralph D. Fleming
Alternative Fuels Specialist
Heavy Duty Transport and Fuels Integration Branch
Office of Vehicle and Engine R&D
Conservation and Renewable Energy
Department of Energy
Washington, D.C. 20585

Dear Dr. Fleming:

Beech Aircraft Corporation has reviewed the draft report prepared by the Aerospace Corporation under contract to the Department of Energy, Office of Vehicle and Engine R&D, and is pleased to submit its written comments in response to the Aerospace Corporation's "Assessment of Natural Gas Application To Automotive Vehicles". Beech Aircraft Corporation further expects that its response to the Aerospace Corporation assessment will be published in its entirety, as a part of the final report.

AEROSPACE CORPORATION STATEMENT (AC):

BEECH AIRCRAFT CORPORATION RESPONSE (BAC):

1. AC-"Current LNG systems add 170 to 200 lb. to the weight of a midsize car or light-duty truck..." (p.1,para.3)

   BAC-A fully fueled 18-gallon liquefied methane fuel system using 5083 series aluminum weighs 112 lbs. vs. 128 lbs. for a comparable gasoline system. This weight advantage applies to all size liquefied methane tanks vs. comparable gasoline fuel systems.

2. AC-"In operation, the fuel is driven from the tank by the vapor pressure, which is controlled in response to increases caused by heat leaks to the -259° liquid and reductions caused by the withdrawal of fluid". (p.2-8, para.1)

   BAC-This statement is misleading. Heat leak to the tank is constant. With a vapor-feed system, a heat exchange coil may be used to control pressure in the tank.

3. AC-"...an LNG tank...has more connections which could leak..." (p.2-9, para.4)

   BAC-Connections on an LNG tank are equal to or less than those on a comparable CNG system. Beech Aircraft Corporation employs

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P.O. Box 85
Wichita, Kansas 67201

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3. BAC - cont'd.

proper engineering practices in safely venting such leaks. Beech Aircraft Corporation cryogenic systems designs are based on the advancements made in low temperature technology during Beech Aircraft's involvement in the United States space program. These included: new and improved manufacturing processes associated with the fabrication and assembly of cryogenic systems, improved cryogenic instrumentation, servicing and control equipment,and new and improved insulation materials and insulation systems designs.

4. AC-"BAC has installed its LNG system in a 171 CID engine..." (p.2-12, para. 3)

BAC-The 1980 Pontiac Phoenix, per Beech Equipment Engineering records, is equipped with a 173 CID (2.8 liter) V-6 engine.

5. AC-"The trunk-mounted LNG tank (Ford's Fairmont experimental car) has a capacity of 18 gallons, but is only 80 percent full to provide an initial 20 percent vapor space". (p.2-12,para.2)

BAC-The BAC cryogenic tank assembly is designed with a vapor-space that is not included in the usable quantity.

6. AC-"A liquid withdrawal system is under development by Ford to accomodate higher fuel flow rates and more complete filling of the tank". (p.2-12, para. 2)

BAC-Beech Aircraft has supplied all cryogenic equipment to Ford and Beech has developed a liquid-feed system.

7. AC-"The installation..(of an LNG tank in the BAC Pontiac Phoenix) differs from the Ford vehicle in the complete filling of the LNG tank..." (p.2-12, para.3)

BAC-The tank assembly in the Ford Zephyr and the Beech Phoenix are identical in operation. External plumbing configuration is slightly altered with no effect on performance.

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P.O. Box 85
Wichita, Kansas 67201

Cable Address "Beechcraft"
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8. AC-"Endurance tests, consisting of both city and highway driving, have been conducted by BAC on a prototype car with a 151 CID engine". (p.2-12,para. 3)

   BAC-The Pontiac Phoenix, per Beech Equipment Engineering records, is equipped with a 173 CID (2.8 liter) V-6 engine.

9. AC-Reference in Section 2.1.2.3 (Methanol) to Ford vehicle adaptation to Methanol (p.2-13, para 2)

   BAC-It should be emphasized that the Methanol adaptation of the Ford vehicle required internal engine modifications to allow it to run on neat methanol. LNG and CNG conversions require no internal engine modifications. Internal engine modifications would certainly increase the gaseous fueled engine's performance, but are not neccessary to operate the vehicle.

10. AC-"The biggest disadvantage of natural gas is in its gaseous nature, which results in a significant reduction in peak engine power". (p.2-31, para.1)

    BAC-The concensus of operational experience with natural gas has been that 100 cubic feet (LHV=100,000 BTU) are equivalent in average driving to one gallon of gasoline (LHV=114,000 BTU). During extended operation at fairly high power-such as freeway driving-the BTU/mile consumption tends to become equal for the two fuels, and 100 cubic feet of natural gas will not equal one gallon of gasoline. During stop-and-go driving, the absence of an accelerator pump and the very lean idle mixture with natural gas results in very favorable BTU/mile figures, and 100 cubic feet will more than equal one gallon of gasoline.

11. AC-"Engine Coolant is not very helpful when starting the engine on LNG fuel and can be frozen in the heat exchanger". (p.2-53, para.3)

    BAC-The temperature differential between the engine coolant and the LNG, even with a cold engine, is sufficient to vaporize the LNG fuel. Normal operation of the vehicle with proper coolant level and antifreeze concentration will prevent any freeze-up in the heat exchanger.

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Wichita, Kansas 67201

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Telex No. 417-422

12. AC-"Above a preset value of about 40 psig, it (LNG tank) operates in a vapor withdrawal mode". (p.2-54, para.2)

BAC-The Beech system entrains vapor in the liquid feed above the pressure set point which reduces pressure but maintains performance in vehicle operation.

13. AC-"The LNG tank was conservatively assumed to be filled to only 80 percent of capacity to provide startup gas and to allow for slow pressure buildup due to heat leaks". (p.2-55, para.2)

BAC-Filling the LNG tank to 80 percent of capacity is not required, and unreasonably penalizes the LNG system.

14. AC-"...on a gasoline energy-equivalent basis, the three fuels deliver the same fuel economy, 25mpg$_{ge}$". (p.2-58, para.3)

BAC-The concensus of operational experience with natural gas has been that 100 cubic feet (LHV=100,000 BTU) are equivalent in average driving to one gallon of gasoline (LHV=114,000 BTU). When the engine ignition timing is properly set, a shaft horsepower increase of 6-8% is realized with an LNG mono-fuel system as compared to a gasoline system. During extended operation at fairly high power-such as freeway driving-the BTU/mile consumption tends to become equal for the two fuels, and 100 cubic feet of natural gas will not equal one gallon of gasoline. During stop-and-go driving, the absence of an accelerator pump and the very lean idle mixture with natural gas results in very favorable BTU/mile figures, and 100 cubic feet will more than equal one gallon of gasoline.

15. AC-"Beech Aircraft Corporation has developed an LNG conversion kit for automobiles, and has installed a system in a 1980 model year Pontiac Phoenix, equipped with a 151 CID engine and manual transmission". (p.2-95, para. 1)

BAC-The 1980 Pontiac Phoenix, per Beech Equipment Engineering records, is equipped with a 173 CID (2.8 liter) V-6 engine.

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Wichita, Kansas 67201

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16. AC-Reference in Section 2.3.3.3 (Beech Aircraft Corporation) to fuel economy achieved with the 1980 Pontiac Phoenix as compared to fuel economy of a similarly equipped gasoline system. "For comparison, the combined fuel economy of a 1980 similarly equipped 49-states certification vehicle is 27 mpg". (p.2-95, para. 2)

    BAC-Environmental Protection Agency handbooks predict 22 mpg for this vehicle.

17. AC-"The resource potential of manure as a source of methane for vehicle use is ...considered negligible". (p.3-25, para.3)

    BAC-Per"Model Literature", Bio-Gas of Colorado, Inc., barn or confinement manure collected daily from beef cattle yields approximately 40 cu. ft. of methane per head. One-hundred head of cattle would yield 48 gallons of LM daily, an amount sufficient to totally fuel a small fleet (8 vehicles) with each vehicle averaging 6 gallons of LM fuel per day (5 gallons of gasoline).
    Also ignored in the analysis is the resource potential of CO_2, which makes up approximately 40% of the gas generated through anaerobic digestion. Because of enhanced oil recovery techniques currently being utilized, CO_2 has a market value of up to $3.00 per mcf in some localities.

18. AC-Table 3-17. Natural Gas Supply System Efficiencies (p.3-77)

    Line Title: "Compressed Natural Gas".

    BAC-This title, while explained in the text, is misleading in the context of the report. In the report, terminology "compressed natural gas" implies a fuel ready for use by the vehicle. In this table, the end use gas has not been compressed to vehicle use pressure levels; therefore, efficiency comparisons are invalid.

    AC-Reference in Table 3-17 to specific natural gas supply systems (i.e., Extraction and Gathering)

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P.O. Box 85
Wichita, Kansas 67201

Cable Address "Beechcraft"
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18. cont'd.

BAC-LNG peak shaving from a utility site should be included as a separate supply system. On site liquefaction at the source should also be included as a separate supply system. In this case, the pipeline transport efficiency of 0.93 should not be considered, thus making the system efficiency for LNG 0.80, not 0.75 as shown.

19. AC-Table 3-19. Production Efficiencies For SNG From Coal (p.3-96)

BAC-Production efficiencies for SNG from coal includes for LNG, pipeline transport efficiency. In this case, on site liquefaction at the source should be included as a specific supply system. By excluding the pipeline transport efficiency, the system efficiency becomes 0.52, rather than 0.49 as shown.

20. AC-Table 3-22. Production Efficiencies For SNG From Wood (p.3-107)

BAC-Production efficiencies for SNG from wood includes for LNG, pipeline transport efficiency. On site liquefaction at the source should be included as a specific supply system. By excluding pipeline transport efficiency, system efficiency becomes 0.49, rather than 0.46 as shown.

21. AC-Table 3-29. Production Efficiencies For Methanol From Natural Gas, Coal, Wood and MSW. (p.3-143)

BAC-The production efficiencies for CNG and LNG should be included in the table along with production efficiencies for methanol, so that a side-by-side comparison can be made.

	NG	COAL	WOOD	MSW
CNG	0.86	0.56	0.53	0.48
LNG	0.80*	0.52*	0.49*	0.41*
METHANOL	0.58	0.60	0.52	0.39

* Excluding pipeline transport efficiency

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22. AC-Table 4-2. Efficiency of Processes From Energy Source To Vehicle Input.
Energy Resource: Coal. (p. 4-4)

Total efficiency for liquefied synthetic NG . . .0.47

AC-Table 4-3. Efficiency of Processes From Energy Source to Vehicle Input.
Energy Resource: Wood. (p. 4-5)

Total efficiency for liquefied synthetic NG. . . 0.44

BAC-Efficiency of processes from energy source to vehicle input on these two tables include transport for LNG prior to product clean-up and liquefaction. This approach disregards the possibility of on-site liquefaction of coal and wood gases. By considering the on-site liquefaction possibility, the process efficiencies become:

Table	LSNG Data Presented	LSNG Data Excluding Transport
4-2	0.47	0.51
4-3	0.44	0.47

23. AC"These engine parameters are representative of current recommended practices in which basic spark timing is not advanced and the engine is operated at 0.8 fuel-air equivalence ratio for control of emissions". (p.4-9, para. 1)

BAC-In virtually all current literature on gaseous fueled vehicle conversion, the recommendation is to advance the spark timing.

24. AC-Table 6-9. Summary of Relative Hazards Based on Fuel Properties.

"In Table 6-9 leakage was ranked according to fuel viscosity and pressure at storage conditions". (p.6-22, para. 1)

BAC-The leakage ranking for methane is listed as five (on a scale from one to six). The difference in storage pressures for CNG (2400 psi) and LNG (60 psi) have not been identified.

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24. BAC- cont'd.

Failure to make the distinction between CNG and LNG penalizes LNG. Relative hazards based on fuel properties of CNG and LNG should therefore be ranked separately.

AC-Volatility ranking for gasoline listed as three. Volatility ranking for methane listed as five. Flammability ranking for gasoline listed as two. Flammability ranking for methane listed as four.

BAC-The U.S. Coast Guard ranks LNG 19th out of 22 hazardous materials that pass through U.S. ports. Gasoline is ranked sixth. Additionally, the Department of Energy and the National Bureau of Standards have not been able to achieve detonations in unconfined vapor clouds of natural gas (methane).

25. AC-Section 6.4.2 Isolation of Fuel System Components (p.6-24,para.1)

BAC-Additional isolation materials and methods are not mentioned.

a. Foam barrier in trunk

b. Positive passenger compartment ventilation

26. AC-"The approach has been employed recently by the Ford Motor Company in a prototype single-fueled LP-gas sedan". "Ford has also reported the development of a CNG fueled Escort automobile..." (p.6-40,para.3)

BAC-The referenced Ford vehicles are identical Mecury Zephyrs, not a Ford Escort.

27. AC-"Furthermore, no vehicles using LNG systems were crash tested". (p.6-42, para. 3)

BAC-This statement contradicts the data presented in Section 6.5.1 and 6.5.3. The DOT sponsored dual-fuel motor vehicle safety impact testing in 1970-1, which included sled tests to generate test data for use in developing crashworthy retention systems for gas storage vessels, to be mounted in automotive vehicles equipped with dual-fuel systems. Four sled tests were conducted on LNG systems:

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27. BAC- cont'd.

Test 242 F-1	Unit:Brencar LNG Body Buck: 1966 Ford Fairlane Impact Speed: 30.8 mph
Test 242 F-2	Unit:Brencar LNG Body Buck: 1959 Chevy P/U Truck Impact Speed: 30.4 mph
Test 242 F-3	Unit:Essex LNG Body Buck:1966 Ford Fairlane Impact Speed: 30.8 mph
Test 242 F-4	Unit:Ametex/Straza LNG Body Buck: 1966 Ford Fairlane Impact Speed: 30.4 mph

28. AC-User Economics of Natural Gas As A Vehicular Fuel (p.7-1)

BAC-An exhaustive economic discussion is provided for NG conversions, indicating filling station prices and conversion costs with various scenarios on fuel price and consumption parameters. Methanol was identified throughout the assessment as an alternative liquid fuel, and was compared with CNG and LNG. Although safety, supply, and environmental impacts are definitely important to fleet operators using alternative fuels, the economic impact of alternative fuel utilization is of primary concern to the fleet operator. Therefore, the user economics of methanol as a vehicular fuel should be subject to the same scrutiny as the user economics for natural gas (CNG and LNG).

29. AC-Vehicle Safety Aspects

"Three specific safety technology development needs have been identified as a result of the review of available information on the safety of gaseous fueled vehicles relative to conventional vehicles". (p.8-2)

1. Conduct additional vehicle impact test programs to confirm the adequacy of gaseous fuel systems and their mounting provisions for LNG systems and for CNG systems using current and lightweight cylinder designs.

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29. AC- cont'd.

2. Perform a fire test evaluation of CNG and LNG tank systems, including pressure relief provisions, CNG cylinders conforming to U.S. and Italian regulations, and light-weight composite cylinders of filament reinforced aluminum alloy.

3. Promote the development of standards for the design, manufacture, performance, installation and inspection of natural gas fuel systems. (p.8-3,8-4; items 1-3)

BAC-House Science and Technology Committee commentary on the Methane Transportation Research, Development and Demonstration Act of 1980: (H. Rpt. 96-1237, August 20, 1980)

> "In summary, the Committee is convinced that there is a legitimate federal role to be played at this point in the development of methane vehicle technologies. While private sector demonstrations have been conducted and some emissions and crash tests have been carried out, questions continue to arise in the areas of safety and air quality. The experience that exists to date has been overwhelmingly favorable, but those lingering questions have hindered commercialization of this technology. The demonstrations and research and development activities authorized under this legislation will give the federal government the necessary information to respond to those questions in a comprehensive manner and, at the same time, to resolve technical questions and improve on present technology. The Committee is confident that this small, short-term program offers considerable promise in terms of petroleum savings and is particularly attractive in that it will encourage locally available energy resources to meet local transportation needs."

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Should you require any additional information, please feel free to contact me at any time.

Sincerely,

Roy E. Adkins

Roy E. Adkins
Director
Alternative Energy Division

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P.O. Box 85
Wichita, Kansas 67201

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December 22, 1981

Dr. Ralph D. Fleming
Mechanical Engineer
Heavy Duty Transport and Fuels Integration Branch
Office of Vehicle and Engine R & D
Conservation and Renewable Energy
Department of Energy
Forrestal Building
Washington, D.C. 20585

Dear Dr. Fleming:

Beech Aircraft has reviewed the draft of the executive summary prepared by the Aerospace Corporation under contract to the Department of Energy (DOE), Office of Vehicle and Engine R & D. We are pleased to submit the following written comments, and expect that these comments will be incorporated into the final report on the use of methane as a fuel for automotive fleet vehicles.

AEROSPACE CORPORATION STATEMENT (AC):

BEECH AIRCRAFT CORPORATION RESPONSE (BAC):

1.AC- "NG now costs up to $0.80 less than gasoline per equivalent gallon, but this is expected to diminish". (pg.xi,para. 4)

BAC- The DOE/Aerospace position that the current cost advantages of natural gas (methane) compared to gasoline is expected to diminish is too negative. Several authorities, including The Gas Research Institute, The Institute of Gas Technology, and DOE's own Energy Information Administration have published reports indicating that rather than diminishing, the advantage is expected to increase. The E.I.A. report, published in March 1980, forecast an estimated price of $3.80 per gallon for petroleum-based fuel by 1990, versus $0.87 per gallon for LNG by 1990.This was compared to the current national average of $1.31.8 for gasoline and $0.40 per gallon for natural gas.

2.AC- "Conversion kits for LNG exist, but are no longer commercially available". (pg. xiii, Fuel System Technology, item 2).

BAC- Commercial fuel conversion kits are being produced and marketed in the United States by several companies, including Beech Aircraft, Essex Cryogenics and Cryogenic Engineering Inc.

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3. AC- "No kits are available for diesel engines". (pg.xiii, Fuel System Technology, item 2).

   BAC- Diesel engine conversion kits are available from Cummings Engine Company for most of their engines, upon request.

4. AC- "Future gas supply depends on government policies, technological advancements, and economic incentives. Due to uncertainties in these factors, gas supply projections for the year 2000 vary from 15 percent less to 50 percent more than present levels". (pg. xiv, Fuel Supply, item 1.)

   BAC- The DOE/Aerospace position regarding natural gas supplies is contrary to several highly qualified organizations, including The Gas Research Institute, The Institute of Gas Technology and the National Geological Survey.

5. AC- "In principle, both NG and methanol possess some very desirable characteristics as automotive fuels. However, to take full advantage of each fuel's attributes while minimizing its disadvantages requires major modifications to a vehicle optimized for gasoline, and in practice this is rarely done". (pg.8, para.4)

   BAC- Engine modifications alone for methanol amount to over $2,200.00, according to Congressional testimony given by Bank America and United Parcel Service officials in early 1981.The DOE/Aerospace statement that "with relatively minor modifications of engine hardware and fuel system materials, existing automobiles may be converted to methanol operation"(pg. 13, para.3) contradicts this testimony. Beech Aircraft is in agreement with the Aerospace Corporation as to the fuel conversion costs quoted for liquefied methane. In addition, modification and installation of liquefied methane fuel systems can be accomplished in less than 8 hours, with the major portion of the time devoted to installation of the tank in the trunk space.

Should you require any additional information, feel free to contact me at any time.

Sincerely,

Roy E. Adkins

Roy E. Adkins
Director of Programs-Alternative Energy Division

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GLOSSARY

AALA	American Automotive Leasing Association
ACL	Alcohol Conversions, Ltd.
ADL	Arthur D. Little, Inc.
AFSI	Advanced Fuel Systems, Inc.
AGA	American Gas Association
AIT	autoignition temperature
ANGTS	Alaskan Natural Gas Transportation System
AT	Autotronic Controls Corporation
atm	atmosphere
BAC	Beech Aircraft Corporation
BCF	billion cubic feet
BETC	Bartlesville Energy Technology Center
BOD	biochemical oxygen demand
BPD	barrels per day
BTC	before top center
BTDC	before top dead center
Btu	British thermal unit
CARB	California Air Resources Board
ccf	hundreds of cubic feet
CDI	capacitive discharge ignition
CFR	Cooperative Fuel Research (Council); also Code of Federal Regulations
CGA	Compressed Gas Association
CH_4	methane
CHP	California Highway Patrol
CI	compression ignition
CID	cubic inch displacement
CNG	compressed natural gas
CNGS	CNG Services, Inc.
CO	carbon monoxide
CO_2	carbon dioxide
CR	compression ratio

CRG	Catalytic Rich Gas (process)
cscf	hundreds of standard cubic feet
DCF	discounted cash flow
deg	degree (angular)
DEI	Dual Energy, Inc.
DFSI	Dual Fuel Systems, Inc.
DFVLR	German Air and Space Research Institute
DOE	Department of Energy
DOT	Department of Transportation
DRI	Data Resources, Inc.
ECE	Economic Commission for Europe
ECMI	Essex Cryogenics of Missouri, Inc.
EGR	exhaust gas recirculation
EPA	Environmental Protection Agency
FHWA	Federal Highway Administration
f.o.b.	free on board
g	gram (mass) or gravity (acceleration)
gal	gallon
gal_e	energy-equivalent gasoline or diesel fuel gallon
GC	Gibson Cryogenics, Inc.
G&E	gas and electric
GPY	gallons per year
gr	grains
GRI	Gas Research Institute
GSA	General Services Administration
GSEC	Gas Service Energy Corporation
GVW	gross vehicle weight
GVWR	gross vehicle weight rating
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulfide
HC	hydrocarbon
He	helium

HHV	higher heating value
hr	hour
IACP	International Association of Chiefs of Police
ICI	Imperial Chemical Industries
IDI	indirect injection
IGT	Institute of Gas Technology
ihp	indicated horsepower
ITA	International Taxicab Association
KEP	Kaiser Electro Precision, Inc.
km	kilometer
K-T	Koppers-Totzek
L	liter
LANL	Los Alamos National Laboratory
LBT	leanest (air-fuel ratio) for best torque
LH_2	liquid hydrogen
LHV	lower heating value
LNG	liquefied natural gas
LNGS	LNG Services, Inc.
LPG	liquefied petroleum gas
LVW	linked vertical well
MAN	Maschinenfabrik Augsburg-Nurnberg A.G.
MBT	minimum (spark advance) for best torque
MHF	massive hydraulic fracturing
MJ	megajoule
MRG	Methane Rich Gas (process)
MSW	municipal solid waste
MTBE	methyl tertiary butyl ether
MVMA	Motor Vehicle Manufacturers Association
m^3	cubic meter
Mcf	thousand cubic feet
mg/ℓ	milligram per liter
mi	mile
mmBtu	million Btu

mmcf	million cubic feet
mmscf	million standard cubic feet
mpg	miles per gallon
mpg_e	miles per gallon, gasoline or diesel fuel equivalent
N_2	nitrogen
NAFA	National Association of Fleet Administrators
NBS	National Bureau of Standards
NDIR	nondispersive infrared
NFPA	National Fire Protection Association
NG	natural gas
NGL	natural gas liquids
NGPA	National Gas Policy Act
NO_x	oxides of nitrogen
O_2	oxygen
OCS	outer continental shelf
OEM	original equipment manufacturer
PDU	process development unit
PG&E	Pacific Gas and Electric
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch, absolute
psig	pounds per square inch, gage
quad	quadrillion BTU
R&D	research and development
ROI	return on investment
RON	research octane number
rpm	revolutions per minute
S	sulfur
scf	standard cubic feet
scfm	standard cubic feet per minute
SCGC	Southern California Gas Company
SDB	steeply dipping bed
SI	spark ignition

SNG	synthetic (or substitute) natural gas
SwRI	Southwest Research Institute
TCF	trillion cubic feet
UBF	unburned fuel
UCG	underground coal gasification
U.S.	United States
USGS	United States Geological Survey
VMT	vehicle miles traveled
WOT	wide open throttle

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